

# Main Generator Rotor Maintenance

## Lessons Learned

*Technical Report*

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# **Main Generator Rotor Maintenance**

Lessons Learned

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# PRODUCT DESCRIPTION

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Main generator rotors are constructed and designed to provide decades of reliable and trouble-free operation. However, a number of incidences have occurred over the years that can adversely impact reliable operation of generator rotors and, ultimately, production of electrical power. This report is a guide for power plant personnel responsible for reliable operation and maintenance of main generators. As a guide, this report provides knowledge and experience from generator experts working at power plants, utility companies, and generator service vendors. The report is not intended to provide detailed instructions for generator rotor maintenance; rather, it offers the experience, lessons learned, and best practices from others who have knowledge and expertise maintaining generator rotors.

## **Results & Findings**

Forty-seven best practices and twenty-seven lessons learned from utilities and vendor service providers who have experienced and dealt with rotor issues are included in the report's appendices. The body of this report builds on the best practices and lessons learned with additional information provided by utilities and manufacturers to guide power plant personnel in the maintenance, operation, and possible upgrade of their main generator rotors.

## **Challenges & Objective(s)**

This project provides power plant utilities with a guide based on experiences of other plants in performing rotor maintenance, dealing with significant rotor issues and problems, and rotor refurbishment. In particular, generator system engineers, maintenance engineers and managers, and others directly involved with maintaining and upgrading generator rotor systems will benefit from the report.

## **Applications, Values & Use**

A number of power plants have successfully implemented rotor repairs and refurbishments and have dealt with identifying and correcting rotor problems having the potential of becoming major reliability issues. The experience and knowledge gained by these plants' personnel serve as valuable resources that should be made readily available to benefit the entire electric utility industry. Additionally, equipment manufacturers, service providers, and other vendors have amassed a wealth of information on maintaining, refurbishing, and upgrading generator rotors that also will be valuable to the electric utility industry.

This report makes the knowledge and experience of these plants and vendors readily available. Lessons learned, best practices, and other information collected from power plants and vendors have been used as a means to help others maintain, refurbish, and upgrade their generator rotors.

## **EPRI Perspective**

Providing the experience, lessons learned, and best practices from power plant personnel offers unique insight into generator rotor maintenance. Building on input from utility personnel, this report offers readers an overview of practices and techniques performed by their peers at other power plants.

## **Approach**

The project team developed this report using input from utility personnel with experience maintaining and operating power plant main generators. Survey forms were used to collect basic information on generator rotor maintenance. Responses were received from utilities on 118 generators. The team held discussions with a number of survey respondents to collect further information. Additional information was gathered from generator service vendors and industry literature, including EPRI reports. A number of utility experts reviewed and commented on the draft of this report; their comments and recommendation have been incorporated into the final version.

## **Keywords**

Rotor

Maintenance

Lessons learned

Best practices



## **ABSTRACT**

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This report serves the readers as a guide to the practices of their colleagues at other power plants in regards to operating and maintaining the main generator rotor. By presenting the Lessons Learned, Best Practices and other experience, this report intends to offer a means for the readers to enhance and optimize their rotor maintenance programs. In this report, emphasis is place on issues and problems utilities have had with main generator rotors; on the inspection, test and maintenance processes performed at various power plants; and on the actions utilities have taken when confronted with rotor problems, such as filed winding shorts and dovetail cracking.



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# 1

## INTRODUCTION

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Generator rotors though seemingly simple in appearance, are in actuality remarkably complex structures; comprised of often the best in electrical, mechanical, material and manufacturing expertise and experience at the time they were designed. The rotor must withstand extreme forces acting upon it while securely carrying the field winding to provide excitation to the generator, this more so with turbine generator than hydro generators. Turbine generator rotors turn at 1500 to 3600 rpm and operate at temperatures that can range up to 266°F–311°F (130°C–155°C); must operate reliably for several decades; and must operate for one to two years or longer continuously before maintenance and inspections can be performed. Also, the rotors must be able to withstand occasional transient voltages and currents, and a large number of starts and stops during their designed lifetime. Despite the complex design and severe duty, generator rotors usually operate extremely well and reliably without failure.

However, collective power industry experience as shown that there are reliability problems and issues with generator rotors that can have a severe impact on plants' electrical power production. In recent years especially, generators have been called upon to perform in manner that squeezes their design margins. De-regulation of the electric utility industry has caused a number of plants to be cyclically loaded as opposed to steady base-load operation. Cyclic operation can cause significant thermal and mechanical stresses on the rotor at a rate that was not expected when the rotor was designed and manufactured. Furthermore, cyclic operation causes the rotor to be at low speed whether on turning gear, or at start up and shutdown. Slow speed rotation subjects rotor components, which are normally secured by centrifugal forces at high speed, to flex and move more; thereby, creating fretting wear and low cycle fatigue.

Additionally, increased competition due to de-regulation may cause utilities to decrease the level of maintenance performed and increase the maintenance interval, thus allowing problems to possibly develop and go undetected. The rotor forging, field conductors, insulation system, wedging and other rotor components may suffer significantly from the higher cyclic loading and decreased maintenance.

Issues from the rotors' design, which were not known until years after manufacture, have created concerns such as retaining ring cracking, dovetail cracking and top tooth cracking. Furthermore, plants looking to uprate their generators to produce more power with the same equipment may find that their generator rotor limits them. A refurbishment, rewind, or replacement of the rotor may be needed to overcome design limitations or rotor problems which can prevent uprated production. Even with rotors, which are suitable for uprated power production, issues can arise due to increased thermal and mechanical stresses on the rotor.

Complicating generator rotor issues is the fact that a rotor's remaining life can be difficult and possibly even impossible to reliably estimate. Some prediction is possible; however, the various components and the number of stresses acting upon the rotor can create numerous failure scenarios. Assessments can be made utilizing predictive techniques and inspection findings providing an assurance that a rotor will be reliable for one or two more operating cycles. But pass one or two cycles, the level of assurance decreases. By monitoring the rotor condition and addressing issues that can potentially damage the rotor will minimize the risk of failure and maximize reliable rotor life.

Many electric power plants have dealt with and have addressed main generator rotor issues, concerns, faults and failures that others in the industry are experiencing or will be experiencing. The plants that have dealt with and addressed generator rotor problems will have significant experience dealing with rotor problems, and have had "Lessons Learned" and have found "Best Practices" that will greatly benefit others in the industry facing similar rotor problems.

Original equipment manufacturers (OEMs) and generator service providers have extensive experience with a wide variety of generators, not only with design and maintenance but also with rotor upgrades and retrofits to address many issues. This vendor experience can also be of great benefit to those in the utility industry, providing invaluable lessons and practices in maintaining and refurbishing generator rotors.

The experience, "Lessons Learned" and "Best Practices" from both utilities and vendors, which can be of benefit to the industry, include:

- Rotor diagnostic practices and techniques;
- Rotor maintenance to eliminate, or at least minimize rotor problems;
- Decision on whether to run, repair or replace the rotor; and
- Solutions to specific rotor issues and problems.

The primary benefit of the experience, "Lessons Learned" and "Best Practices" gathered for and presented in this guide, will be plants being able to maximize the efficiency of their generator operation and maintenance by pooling information from throughout the electric utility industry so that all will benefit.

Thirty utilities have provided information and shared their experience in the making of this guide. These thirty utilities include one hundred twenty-six different generators of various manufactures. The various manufacturers include: AEI, Allis Chalmers, Alstom Power Ltd, ASEA, BBC, CGE, DHIC, English Electric (GEC), GE, Hitachi, NEI Parsons, Parsons, Siemens, Toshiba and Westinghouse. A number of generator manufacturers and service providers have also contributed valuable information and expertise. Of the make of generators for which information was provided, General Electric and Westinghouse were the most prevalent; with approximately thirty percent of the generators made by GE and twenty-five percent made by Westinghouse.

# 2

## KNOWN INDUSTRY PROBLEMS

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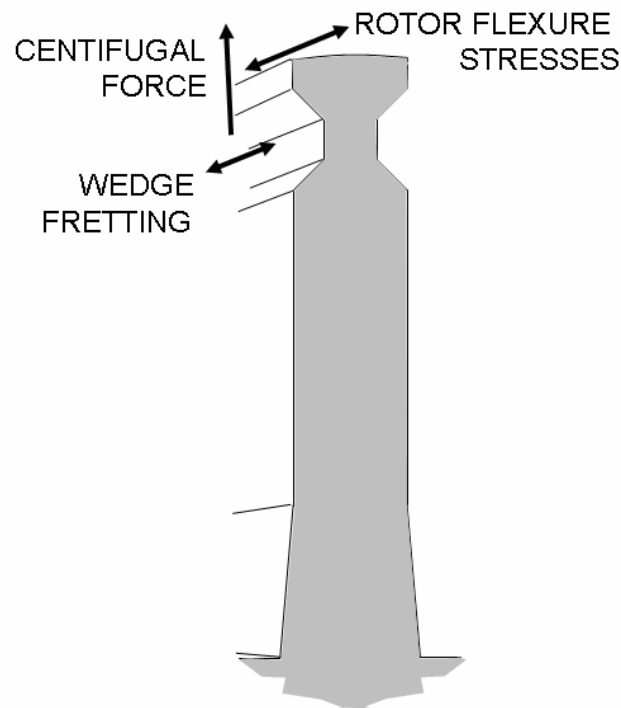
Generator rotors typically provide years of reliable service with proper maintenance and operations. The components that make up a rotor have to be designed to handle a variety of mechanical, electrical and thermal stresses which include centrifugal force, thermal expansion and possible field over-voltages; and handle these stresses without failure for forty years or longer. Turbo-generator rotors operate typically from 1500 to 3600 rpm producing extreme centrifugal forces in the rotors.

Hydro generator rotors have a much lower rpm, but still experience some degree of centrifugal force. These rotors are typically of the salient pole design due to the significantly lower centrifugal stresses. Looseness, and material flaws in the windings and iron, can be worsened by centrifugal force.

Several issues and problems have come to light, particularly during the last two decades, impacting a number of generators. These issues and problems may be due to design, manufacturing, operation, or a combination of these factors. Rotor tooth cracking is a problem about which many utilities are concerned. Top tooth and dovetail cracking can have several factors contributing to the problem. These contributing factors are included in design, material and operational issues.

One operational issue that has become more prevalent is cyclic generator operation, or two-shifting, in which the generator is run for part of the day during high transmission system load, and then shut down the rest of the day. This cyclic operation flexes the rotor as a whole as well as the individual components of the rotor. The flexing, including cyclic centrifugal forces, as well as fretting from thermal expansion and contraction of the rotor and winding wedges may precipitate and aggravate cracking in the rotor teeth.

Utilities have a major investment in their generators and take measures to ensure the reliability and availability of their equipment. However, events such as severe grid disturbances and equipment failure may create operational issues impacting the health of generator rotors. An example of this is a transmission system fault creating negative sequence currents, which produce stresses on rotor components and lead to heating and possibly arcing in the rotor.



**Figure 2-1**  
**Rotor Tooth Stresses**

It is important to note, that while a number of major issues appear to occur mainly on the equipment provided by a few manufacturers, that these manufacturers are the ones having significant percentage of the generators in service. Due to the fact that these manufacturers have a large fleet in service, more problems with their rotors become apparent, possibly leading to the misperception of these manufacturers' generators being particularly prone to problems.

## **Identified Issues and Problems**

The problems and issues identified in the survey for this project and reported in industry literature include:

### ***Cell Slot Liners***

- Migration
- Liner Degradation

### ***Winding Copper***

- Copper Dusting
- Copper Distortion

- Copper Foreshortening
- Moving Conductors
- Spreading of Top Conductors
- End Strap Elongation

### ***Links and Connections***

- Cracks in Damper Links
- Cracks in Pole to Pole connections
- Main Lead Fatigue and Cracking
- Coil-to-Coil Jumpers Distorted and Partially Broken
- Pole-to-Pole Jumper Distortion

### ***Retaining Rings***

- Arcing Damage to the Retaining Ring
- Retaining Ring Stress Corrosion Cracking
- Retaining Ring Pitting
- Retaining Ring Material Removal from Multiple Inspections
- Retaining Ring Seating Cracks
- Top Tooth Cracking

### ***Collectors and Brushes***

- Collector Flashover
- Carbon Brush Dust Accumulation
- Collector Ring Footprint and Other Surface Problems

### ***Winding Insulation***

- Shorted Field Windings
- Partially Shorted Turns at Speed
- Insulation Deterioration
- Crushing of Insulation
- Field Grounds
- Rotor Temperature Monitoring Loss of Calibration

### ***Contamination***

- Construction and Manufacture Debris
- Metal Contamination

### ***End-winding Blocking***

- Missing Blocking
- Loosened Blocking
- Moved Out of Position

### ***Rotor Cooling***

- Poor Design Thermally
- Insulation Blocking Gas Ducts
- Slot Liners Shifted or Migrated, and Blocking Cooling Passages
- General Overheating

### ***Forging Symmetry Issues***

- Asymmetrical Stiffness of Rotor Forging
- Rotor Forging Issues

### ***Rotor Shaft***

- Cracked Shafts
- Keyway Cracking
- Stub Shaft Alignment

### ***Rotor Slot Teeth***

- Dovetail Cracking
- Galling of the Slot Dovetails during Wedge Installation

### ***Rotor Baffle Assembly***

- Baffle Assembly Damage

### ***Slot Liners***

- Slot Cells End Cracking



- Slot Liner Cracks
- Slot Liner Migration

**Rotor Fan**

- Blade Diffuser Damage

**Slot Wedges**

- Packing Clearance Excessive
- Rotor Slot Wedge Cracks

**Reported Rotor Problems**

The following table shows the types and number of problems reported by the one-hundred and eighteen power plant units which provided information to this report.

**Table 2-1  
Reported Main Generator Problems**

<b>Problem</b>	<b>Count</b>
Shorted Field Turns	20
Retaining Ring Stress Corrosion Concerns	15
Liner Issues	9
Movement of Winding Copper	8
Distortion of Winding Copper	6
Main Lead Cracking	6
Dovetail Galling and Cracking	6
Contamination Issues	3
Radial Stud Issues	3
Tooth Top Cracking Issue	3
H2 Seal Problems	3
Bearing Grounds	2
Brush Rigging Grounds	2
End Turn Blocks Loose and Missing	2
Forging Concerns	2
Retaining Ring Arcing	2
Shaft Cracking	2
Slot Wedge Cracking	2
Cooling Problems	1
Fan Cracking Issues	1
Low IR Reading	1
Generator Motoring Event	1
Winding Connection Cracking	1

## **Problem Discussion**

### ***Cell Slot Liners***

Due to copper having a greater thermal coefficient of expansion than steel, and the fact that ohmic heating occurs in the copper, the conductors of the field winding expand more than the steel of the rotor forging. This expansion of the copper can exert a force on the slot material in the direction of the expansion. The slot liner in some rotors can be dragged in the direction of expansion force. Cyclic operation of the generator will produce this thermal expansion caused dragging effect in each heat-up of the field winding. Thus, the slot liners may be moved significantly over numerous cycles.

The movement, migration or displacement of the slot liners can obstruct field-cooling passages, resulting in the possibility of significant blockage in the worst cases. Obstruction of the cooling passages leads to more heating of the conductors which, in turn, can worsen the movement of the slot liners. Additionally, other problems due to overheating, such as insulation degradation and copper distortion, can possibly occur.

Obviously, most generators do not experience slot migration as a problem. Well designed machines provide for the thermal expansion of the conductors and secure the conductors effectively without creating shear stresses, which will move the slot liners. However, even in a well designed machine, other problems may initiate liner movement. These other problems can include significant overheating of the field from excessive field current, and a rotor rewind which was not up to specification.

The thermal expansion of copper can also cause fretting of the liner material. The movement of the winding against the liner, and the liner against the rotor steel if the liner moves, can abrade the liner material. Eventually, the liner may fail from the abrasion, leading to field grounds.

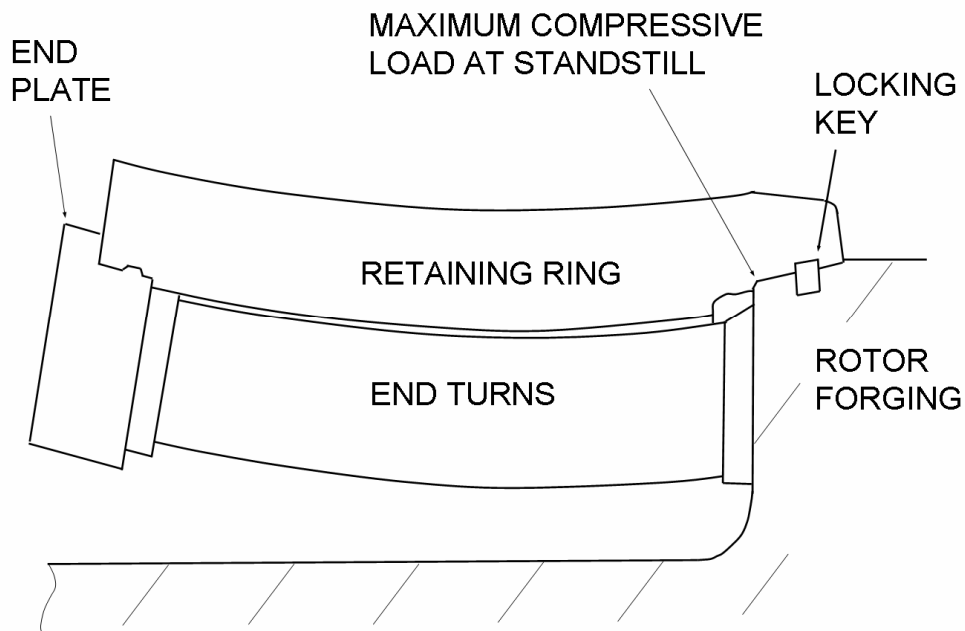
### ***Winding Copper***

Distortion of the rotor copper conductors including foreshortening, elongation and spreading typically take a significant period of time to develop. This distortion can lead to conductor and/or insulation failure. The copper conductors expand more than the rotor steel when heated during operation. If the conductor is unable to expand linearly, the copper will experience an axial compression. Blocking, friction, and pinch points from radial thermal expansion may all contribute to the prevention free linear movement, causing the copper to be under compression. If compressive forces are above the copper's yield point, deformation will occur. After this deformation or distortion occurs, foreshortening results as the conductors cool during shutdown or reduces loading.

The top conductors in the rotor slots are pressed by centrifugal force against the wedges and packing, and can be more restricted from linear expansion than other conductors. This restriction can cause more distortion in the top conductors and produce more spreading of the conductors.

This spreading can be more significant at the ends of the rotor, where the top conductors are pressed against the retaining ring insulation.

The winding end straps or turns may also be pressed by centrifugal force against the retaining ring insulation. As the retaining ring is expanded by centrifugal force, friction forces will pull on the top end straps. Over a number of operational cycles the top end straps can undergo elongation, and possible weakening.



**Figure 2-2**  
**End Turn Stress**

Fretting damage to the insulation liner of the retaining ring can occur if the top end winding is pressed by centrifugal force against the retaining ring. Evidentially, fretting wear will perforate the insulation creating a field ground. Possible arcing and resistive heating from a ground can damage both the end winding and the retaining ring.

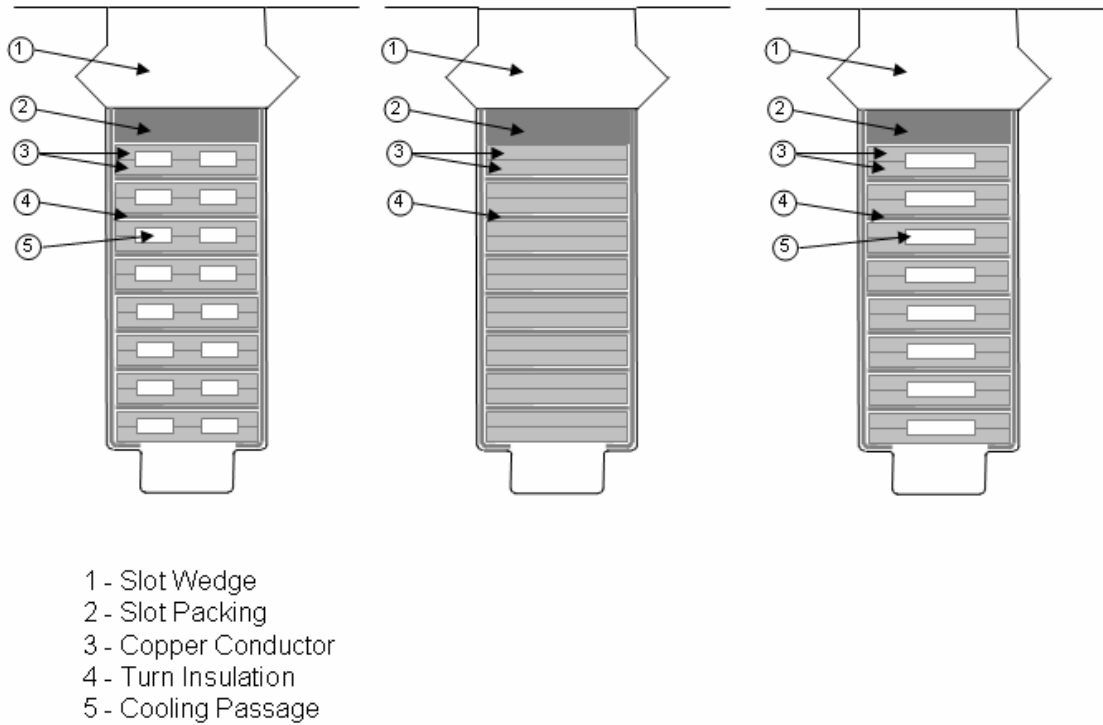


**Figure 2-3**  
**End Turn Arcing Damage**

**Courtesy of Márcio Rezende Siniscalchi, ELETRONUCLEAR**

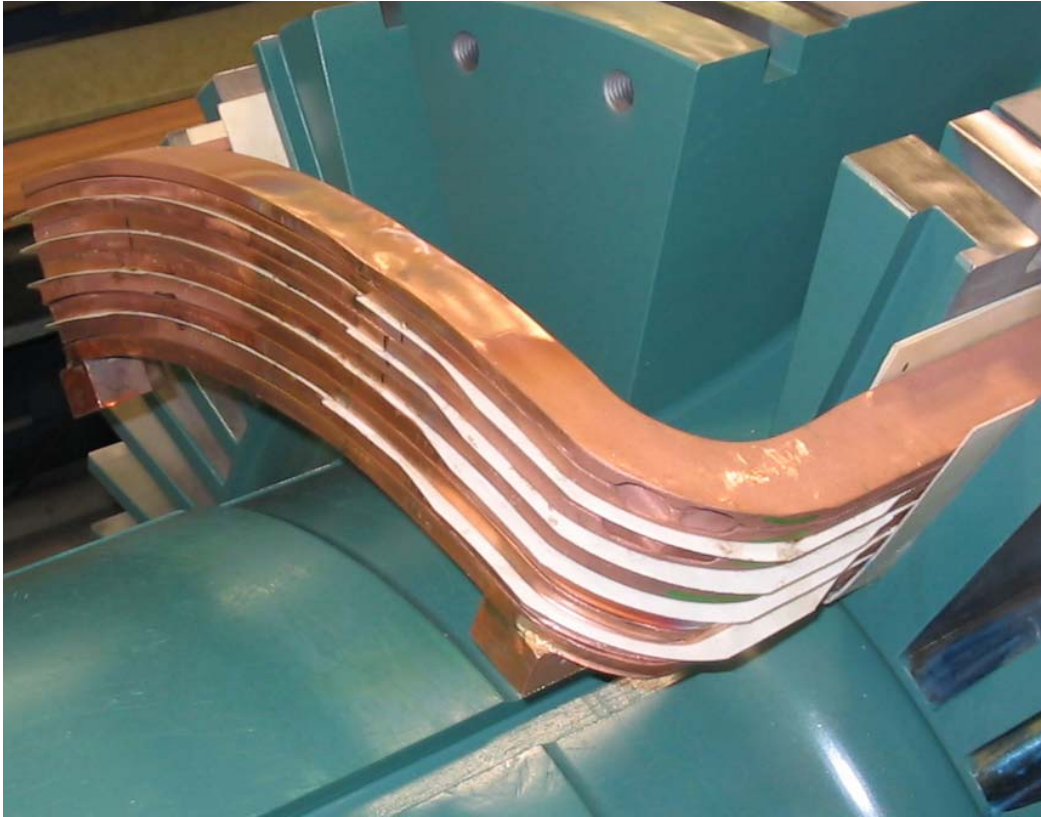
Contributing to copper distortion is rotor overheating, which can cause softening of the rotor's copper. Copper distortion rarely, if at all, occurs in a relative short period of time, but rather develops slowly over years of operation.

Certain field winding designs incorporate two part conductors. These two part conductors are copper bars with C-shaped or E-shaped cross sectional areas, that when install face to face form one or two cooling passages through them. One other two part conductor design is comprised of two flat pieces of copper that does not form cooling passages. Regardless of shape of the two parts making up a conductor, relative movement between the copper parts can cause them to rub and abrade each other. This abrasion wears off some of the copper forming a copper dust. Relative movement of the copper conductor parts may be due to thermal expansion and slight rotor flexing experienced during start-up, operation, and cool down of the generator. Being on turning gear for a period of time may cause significant copper dusting.



**Figure 2-4**  
**Two Part Conductor Cross Sections**

While on turning gear, the windings can be freer to move than when in operation: not having centrifugal force or thermal expansion holding the conductors tightly in position. With each rotation while on turning gear, the individual conductor parts complete a cycle of relative movement, with possible wear against each other.

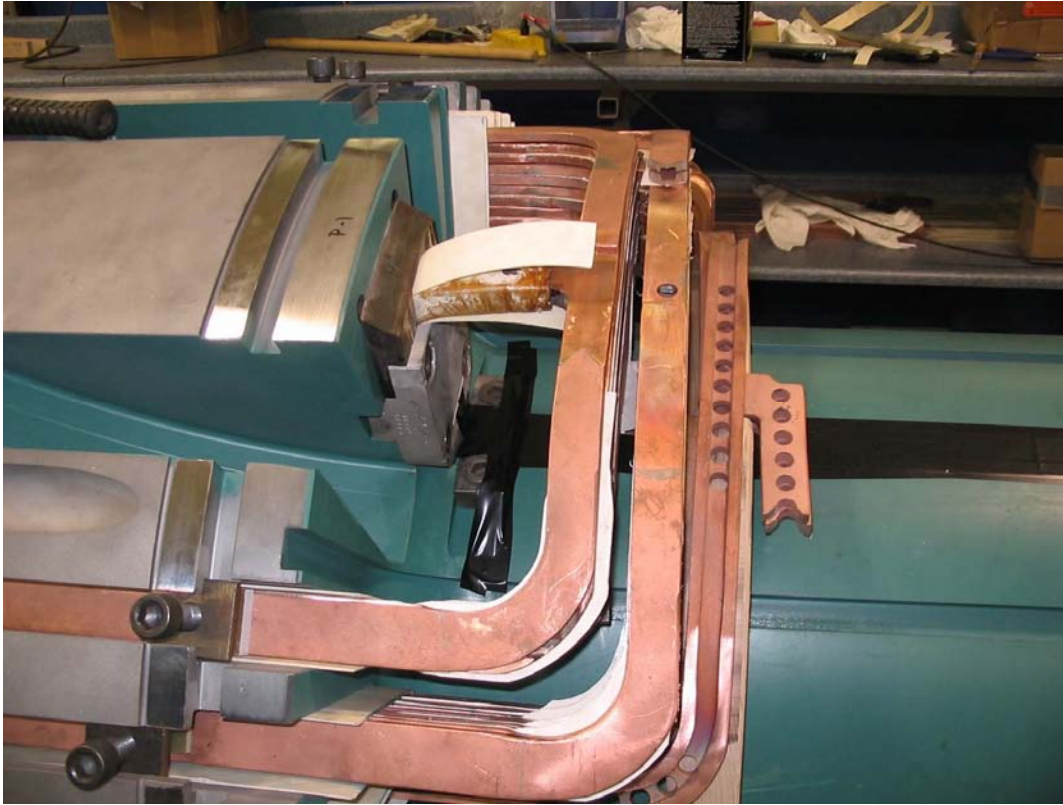


**Figure 2-5**  
**End Turn View of Two Part Conductors During Winding Assembly**

Many generator rotors with two part conductors do not necessarily have problems with copper dusting. In these machines the conductors are sufficiently braced to prevent relative movement, or at least make any movement insignificant. With some designs, the conductor parts are brazed together in spots along their length to more effectively hold them in relative position.

### ***Links and Connections***

The links and connectors for the rotor field winding, including the main field leads, are subjected to same centrifugal and thermal stresses as the winding copper. Pole to pole links and other connections at the rotor ends may be pressed against the retaining ring by centrifugal forces and elongated. Typically distortion of the links and connections occur first and will aggravate the condition causing the distortion leading to cracking of the copper. Furthermore, the distorted copper may cause retaining ring insulation degradation and a possible electrical ground.



**Figure 2-6  
Main Lead Connection to Field Winding, End Turns Still Being Assembled**

**Courtesy of Portland General Electric**

As leads and connectors are securely terminated at both of their ends, cyclic expansion and forces on these conductors can create high stress at or near the terminations. On rotors having problems with leads and connectors, often the problem has occurred near a termination.

Loosening of terminations and connections can lead to localized heating and flexing, which in turn, create a high stress points. Loosening occurs over time from cyclic forces, vibration and thermal expansion/contraction. Additionally, the ties and packing used to secure a connector can loosen over time. This loosening can also lead to increased flexure and fatiguing of the connector.

Bore copper provides a path for field current from the collector or brushless exciter to the windings. The bore copper is not subjected to significant centrifugal forces, as with the conductors at the circumference of the rotor. However, thermal cycling and cyclic rotation can lead to problems with the bore copper. Over time, though not always, the cyclic stress and flexing of the bore copper can lead to degradation of not only the copper, but also of its insulation creating a field ground.



Hydrogen cooled generators will have seals on the radial studs at either one or both ends of the bore copper. The radial studs connect the field winding leads to the bore copper at one end, and the collector to the bore copper at the other end. Generators with brushless exciters may have radial studs at the field end, using butterfly connectors at the shaft's end for connection to the brushless exciter. The hydrogen seals, as the name implies, prevent hydrogen leakage through the shaft. Cyclic stresses and flexing of the bore copper can also put strain on the radial studs and the hydrogen seals; potentially initiate seal failure and hydrogen leakage.



**Figure 2-7**  
**Radial Stud Removed from Shaft**

**Courtesy of Portland General Electric**

### ***Retaining Rings***

As previously mentioned for links and connections, the conductors at the rotor ends may be pressed against the retaining ring by centrifugal forces. Fretting wear of the retaining ring insulation can lead to conductor grounding and arcing damage to the retaining ring.

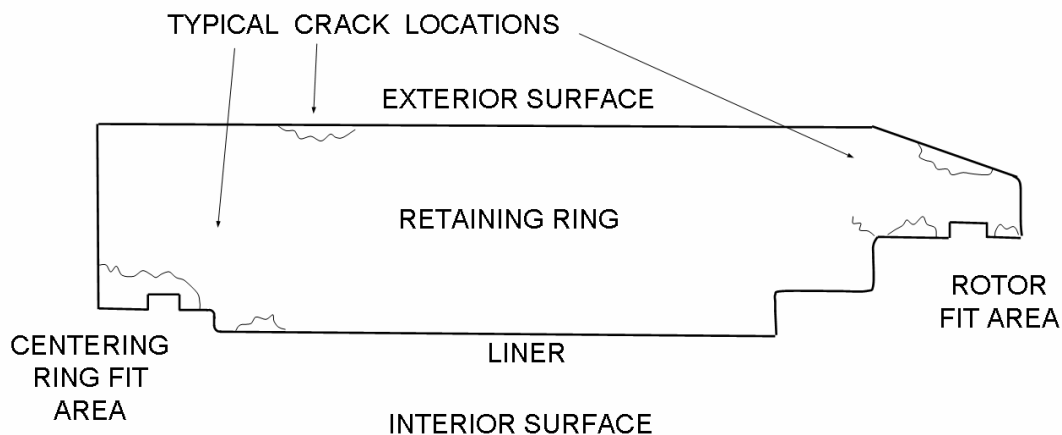
The retaining ring is the most stressed component of the rotor. Significant damage from arcing or other means can eventually cause mechanical failure of the ring creating the risk of catastrophic destruction of the entire generator. The extreme hoop stress on the ring during operation tends to pull the ring apart, thus any significant damage or defect can weaken the ring



to the point it cannot resist the hoop stress. Cyclic operation of the generator, such as two shifting, can cause more fatigue of the ring metal at the point of damage or defect, making that damage or defect more significant. Eventually the ring weakens enough to come apart, with the high centrifugal forces sending pieces of the ring into, and possibly through, other parts of the generator.

Stress corrosion cracking of the retaining ring has received significant attention from the power industry in recent years. Retaining rings typically of 18Mn 5Cr or similar composition are susceptible to stress corrosion cracking when subjected to moisture. The shrunk fitting of the rings on the rotor causes an ever present stress on the rings; this stress with the presence of moisture leads to stress corrosion cracking. During generator operation, centrifugal force reduces some of the stresses. Thus, frequent start up and shut down of the generator produces much cyclic stresses on the rings. The presence of moisture in contact with the ring, and cyclic stresses on the ring from starting up and stopping the generator, promote the propagation of cracking.

As the stress component of this problem cannot be eliminated, so the industry has to focus on the corrosion component of this problem. Monitoring of the cooling medium dryness and periodic inspection of the ring provide some assurance of the soundness of the ring material. The rings need to be properly protected from moisture even during outages when the rings could be exposed to the atmosphere. Inspection for stress corrosion cracking can be difficult or even incomplete without removing the ring from the rotor.



**Figure 2-8**  
**Retaining Ring Cracking**

Cracking can often occur on the under side of the rings where dye penetrant and other visible inspections cannot be readily performed while the rings are mounted on the rotor. Ultrasound testing may reveal possible defects on the underside of the rings, but miss others due to the configuration and composition of the ring. Extensive work is needed to remove the rings for a

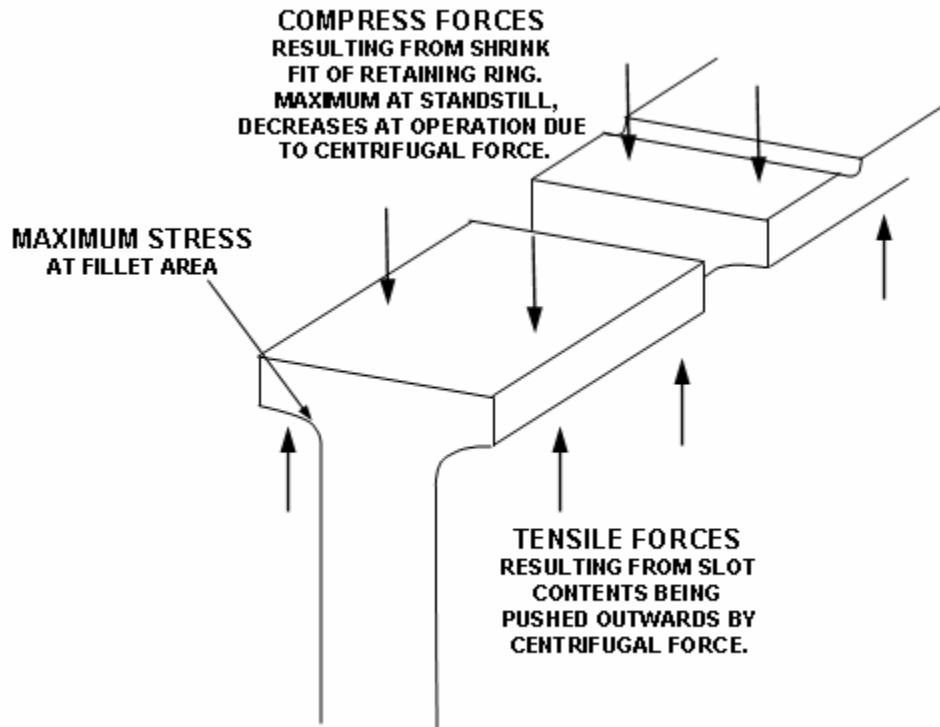
complete and thorough inspection. Ring material may need to be removed to eliminate some corrosion and defects, but only a limited amount of material can be removed without weakening the ring. Care has to be exercised when planning and performing ring material removal, so as not to create new stress risers.



**Figure 2-9**  
**Retaining Ring Removal, Note Heating Coil**

**Courtesy of Márcio Rezende Siniscalchi, ELETRONUCLEAR**

Replacement of the retaining rings with ones made of 18Mn 18Cr stainless steel, or similar material not susceptible to stress corrosion cracking, is the best way to eliminate the risk of stress corrosion failure of the rings. Ring replacement is the recommendation of generator OEMs. However, until replacement rings can be procured and an outage planned to replace the rings, assuring dryness of the ring environment and periodic inspection during preceding outages is necessary.



**Figure 2-10**  
**End Tooth Stress,**

**Courtesy of Márcio Rezende Siniscalchi, ELETRONUCLEAR**

The rotor forging area under retaining rings is subjected to high cyclic stress. Due to a compressive fit, the rings press down on the rotor teeth both at standstill and while on turning gear. At operational speed, centrifugal force relieves a significant portion of the compressive stress on the teeth from the rings. However, centrifugal forces press the field winding upwards against the dovetails, creating a tensional stress on the teeth. The varying cyclic stresses on the teeth under the retaining rings, from generator start up and shut down, can lead to fatigue cracking, or top tooth cracking. Specialized machining of the teeth in the retaining ring seat area can be performed to minimize stress risers in this area, and reduce the risk of cracking.

### ***Collectors and Brushes***

Carbon dust may build up in the collector area due to rapid brush wear, poor ventilation or infrequent cleaning. Frequent inspection of the collector area, including the brush rigging, helps identify dust build up, and avert potential grounding and shorting the field circuit. Inspection of ventilation filters helps ensure adequate airflow across the collectors to remove carbon dust, in addition to providing cooling of the brushes.

Carbon dust build up can create a ground of the field circuit; and at worse if not removed, can cause a flashover on the brush rigging from one polarity to the other. Significant heat from the

flashover arc may melt and damage the rigging, the brush holders and the collector rings. Besides dust build up, flashovers may occur during in-service brush replacement from dropped brushes and loose pigtails. Brush holders specifically designed for in-service brush replacement minimize the flashover risk.

Another collector problem is foot printing on the rings. Foot printing is also referred to as ghosting and photographing. Foot printing occurs from a brush periodically losing or lessening its contact with the ring. The footprint is the result of the brush at that point on the ring making better contact. With the better contact, more current flows from the brush to that point on the ring creating a footprint of the brush.

The ring surface may become hardened at the footprint leading to a high spot on the ring. As the ring surface wears, the harder footprint area wears less; thus, becoming relatively higher than the rest of the ring. Root causes for foot printing can include vibration, weak brush spring, loose brush and a brush restricted from moving in its holder. Consequences from foot printing include increased brush wear and brush chipping.

Other collector problems are excessive ring wear, excessive brush wear, grooving and brush arcing. Excessive wear of the brushes and rings can be due to a number of causes that include: improper brushes, contaminates, insufficient moisture in the air, poor brush contact with ring, and excessive brush pressure on ring. Contaminants and insufficient moisture can cause the surface film on the rings to deplete, thus increasing the friction between the rings and brushes.

### ***Winding Insulation***

The generator field winding insulation is subject to a variety of stresses from mechanical, thermal and electrical actions. Fretting wear can occur from relative movement of the conductor against another object such as the slot wall or another conductor. High voltages and harmonic content can overstress the insulation and lead to its eventual failure. Over heating of the field, which may be due to high current, poor cooling or other factors cause accelerated aging of the insulation. Obviously, insulation failure causes field grounds and possibly shorts in the winding.



**Figure 2-11**  
**Turn Insulation and Ground Wall Insulation with One Turn Installed**

**Courtesy of Portland General Electric**

Shorted turns are not always readily apparent, up to five percent of the field turns may be shorted before the problem becomes noticeable through vibration or increased field current. However, while not necessarily apparent, a short turn can cause localized heating at the short as well as causing damage to components adjacent to the short. The installation of flux probes is often the best means to identify shorted turns. However, flux probe installation does require removal of the rotor during an outage.

Shorted field winding turns, if significant, may be indicated by operational characteristics, such as vibration and field current requirements. The characteristics depend upon the design of the machine as well as the extent of the winding shorts. There are some differences between two pole and four pole generators in regards to their reactions from running with shorted turns.

**Table 2-2  
Characteristics of Two Pole and Four Pole Generator Field Shorts**

Two Pole Machines	Four Pole Machines
Vibration induced by differential heating of rotor forging	Less reaction to the differential heating cause by turns being shorted
No magnetic imbalance, except with significant shorted turns	Vibration induced by magnetic imbalance on the rotor
Increased field current required to maintain generator output	Increased field current required to maintain generator output
More tolerance to shorted field winding turns	Less tolerance to shorted field winding turns

While the above table can aid in indicating the presence of field winding shorts, detailed vibration analysis and off-line electrical testing may be needed to confirm the presence of shorted turns without the aid of an air gap flux monitor. An air flux monitoring system can be quite useful in determining the presence of shorted turns.

The problems resulting from copper distortion can lead to insulation degradation and failure. Besides fretting, crushing of the insulation can occur in areas where distorted copper presses against the insulation. Additionally, insulation may degrade with age, though machines several decades old continue to provide reliable service with the original field insulation. Periodic insulation testing of the field winding will help ensure reliable service for an operating cycle until the next schedule outage.

### **Contamination**

Contamination and debris can create insulation abrasion, wear, punctures and eventual failure. Additionally, conductive contamination leads to field grounds and shorts. Chemical contaminants may attack the insulation, softening or degrading it so that even normal operational stresses fail the insulation.

Debris from installation, manufacture and generator maintenance may be left in the generator if adequate measures are not taken to ensure cleanliness. Besides the insulation damage described in the previous paragraph, tools and other relatively large objects can cause extensive damage to both the rotor and the stator. One instance involved a small file left in the air gap of a gas turbine generator. The rotor damage was repairable, but was so excessive that a long outage extension would be required for repair. A spare rotor had to be procured from another plant to allow the generator to be returned to service sooner.

### **End Winding Blocking**

End wing blocking serves to maintain the conductors in the proper position, to provide support and to prevent undue conductor movement. Age and vibration tend to cause loosening of the

blocking, thus allowing undesired movement of the conductors. Elongation and other distortions of the conductors also contribute to loosening of the blocking.

Moved or missing blocking allows undesired movement of the end winding conductors, which in turn leads to further elongation, distortion and possible conductor cracking. Conductor movement may also lead to fretting and insulation failure with possible damage to the conductors and retaining ring. Additionally, shifted and missing blocking can result in unequal transfer of conductor thermal expansion forces to the rotor forging; thereby possibly causing a slight bow and vibration to the rotor.

### ***Rotor Cooling***

Rotor cooling problems originate from both rotor design and rotor dynamics. Design related problems include cooling path length, incomplete conductor cooling, restricted cooling paths and unsecured slot components. Some rotor designs have long cooling paths through the slots, resulting in insufficient cooling near the exit points of these paths. The cooling gas, such as hydrogen, heats up as it travels axially cooling the conductors; at the end of its cooling path the heated gas has diminished capacity to cool the conductors.

Air cooled generators rely on the rotor to move air through cooling passages. Directly air cooled generators draw air through filters to remove dust and debris. Clogged filters restrict air flow and reduce cooling capability, which can be especially troublesome during times of heavy load and high ambient temperature. Sufficiently clogged filters may collapse, and dump dust and debris into the machine where cooling passages can become clogged. Indirectly cooled generators rely on a heat exchanger to cool the air. One generator design employs a sealed chamber beneath the generator; into which heated air is exhausted and then drawn through a heater exchanger to be cooled before returning into the generator. Debris left in air chambers and air pathways, after an outage for instance, can clog the heat exchanger restricting air flow and decreasing cooling capacity.

Slot cooling paths not designed for smooth aerodynamic flow restrict the flow of cooling gas, not allowing for optimal cooling. While a less than optimal flow does not necessarily cause inadequate cooling; if other parameters, such as flow path length and high cooling gas temperature, are not adversely affecting the cooling. However, if these other parameters are deficient in conjunction with restricted flow, cooling capability will be insufficient to prevent rotor overheating.

When conductors are incompletely cooled, portions of the conductors receive adequate cooling, while other portions do not. Incomplete cooling may be due to excessive flow path length, as described above. Also, incomplete cooling can occur where the design of the flow path omits points on the field conductors such that these points receive inadequate cooling. The insulation at these points suffers more from thermal degradation, and may be damaged from increased expansion of the copper conductors.

Designs which do not adequately secure rotor slot components for the intended life of the generator may allow blockage of some cooling paths. The rotor whether in operation or on turning gear, is constantly flexing a minute amount. The force of gravity bends the middle of the rotor downward, almost indiscernibly. This downward bending while the rotor is turning, even at speed, causes constant flexing of the rotor. The rotor slots are alternating under compression and tension, causing axial expansion and contraction of the slots. Slot liners, packing, and other components may be shifted by the alternating expansion and contraction, possibly causing them to interfere with cooling passages. Additionally, thermal expansion and contraction from cyclic generator operation may contribute to the shifting of slot liners and other components.

Even with well designed and manufactured rotors, some shifting of components should not be totally unexpected. After years and decades of operation, through wear and aging, components can become loose. With loosening, shifting of components becomes possible, to the extent that some blockage of cooling passages can occur. The resulting inadequate cooling, as mentioned before, can lead to conductor, and insulation, distortion and degradation in the affected areas.

Other issues that may adversely affect cooling include over excitation, shorted field turns, decreased hydrogen pressure and decreased cooling water capacity. All these issues cause general overheating of the field, while shorted turns will also create localized hot spots. Typically short will not be a solid connection, and will produce resistive heating. Additionally, shorts decrease the ampere-turns of field, necessitating an increased field current to maintain the generator's excitation, and subsequently cause more resistive heating of the entire winding.

Maintaining the proper pressure ensures sufficient density of the hydrogen, or other cooling gas, to adequately cool the windings. A faulty hydrogen seal may necessitate running with decreased hydrogen pressure to minimize hydrogen leakage. Excitation may need to be decreased to prevent overheating with the reduced gas density and the subsequent reduction in cooling capacity.

The cooling gas is typically cooled by a gas to water heat exchanger. If the heat exchanger water flow is restricted or decreased, heat will not be as effectively removed as it should be from the cooling gas. Consequently the temperature of the cooling gas will be too high to effectively cool the windings. Additionally, fouling of the water tubes in the heat exchanger or high water temperature will also diminish heat transfer capability. Proper heat exchanger maintenance and attention to the chemistry of the cooling water help prevent fouling of the heat exchanger tubes. Load reductions may be necessary during periods of high water temperature to prevent rotor overheating. Water coolers or other modifications may be required to ensure sufficiently low enough cooling water temperatures for all periods of operation.

Overheating of the rotor and winding may occur from negative sequence currents from grid disturbances or motoring of the generator. While the situations are often transient in nature and usually rather brief in duration, sufficient overheating of the field winding and rotor iron may occur to distort conductor copper and damage winding insulation. Situations can occur in which low levels of negative sequence current may exist for long durations of time without being detected. These situations often result from unbalance loading of the generator resulting from



untransposed transmission lines or a high amount of single phase loading. The low level of negative sequence current may not be detected as many plants still rely on older electro-mechanical relays which may not be sufficiently sensitive. The negative sequence current induces current flow on the surface of the rotor, heating areas of the rotor as well possible arcing.

Regardless of whether overheating is transient or continuous, and whether it is localized or general, damage to the field may occur. This damage may not be evident until long after the overheating event has past. Copper thermal expansion may have loosened components leading to increased fretting wear and blocking of cooling. Damaged insulation may eventually fail causing a ground or a short. Many winding shorts go undetected if they are minor and few in number. Moreover, these shorts can be worsened by localized resistive heating of the shorts; causing conductor damage, other shorts and/or a field ground.

### ***Forging Symmetry Issues***

Shorted turns in the field winding likely will not be evenly distributed between the poles. As discussed previously, shorted turns produce general winding heating by causing a larger field current to compensate for the decreased ampere-turns. But also, because the shorts remove turns from pole in which they occur, there will be uneven heating of the rotor.

The rotor forging, because of the uneven heating, will tend to expand more on the side that has the greater heating, causing a slight bowing of the rotor. Furthermore, the copper conductors expand more than the steel of the rotor forging and may exert additional forces acting to bow the rotor. These forces will be greater in the areas having more heating, thus contributing further asymmetry to the rotor.

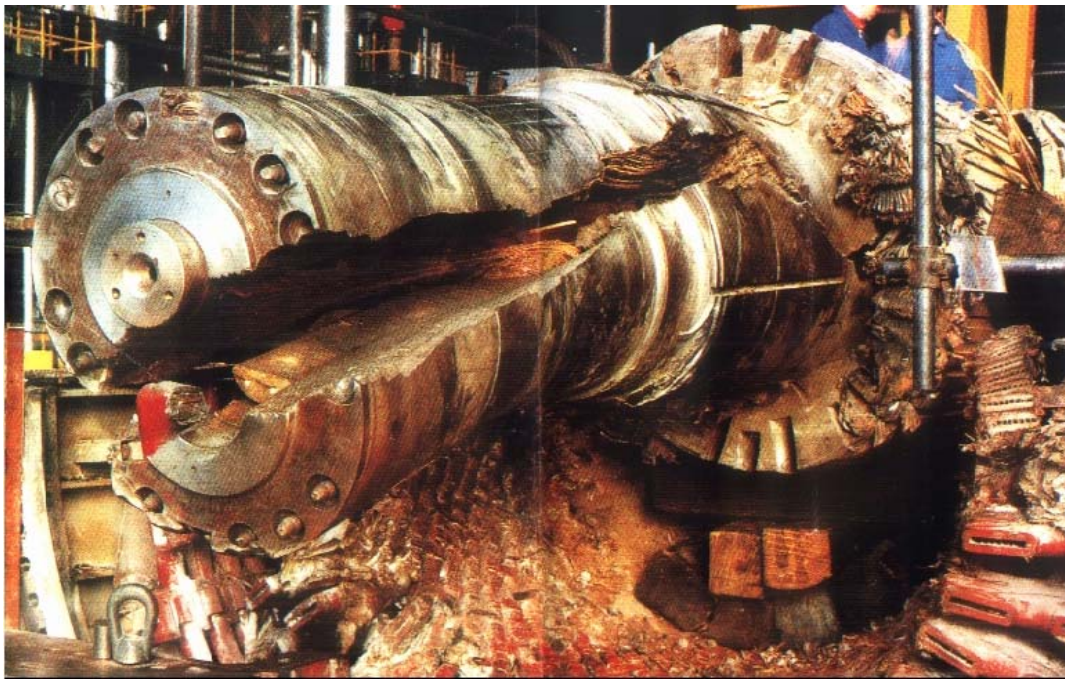
Forging asymmetry manifests itself as vibration. Two pole machines are much more susceptible to asymmetry from uneven rotor heating (thermal sensitivity) than rotors with four or more poles. The greater rotational speeds of the two pole machine and the lower degree of initial symmetry make the two pole rotors much more susceptible.

Besides shorted turns, uneven heating may be due to blocked cooling passages. With cooling restricted in one or more passages, less heat is removed in the affected areas of the rotor and uneven expansion will occur. Wedge tightness and end-winding blocking can affect a rotor's thermal sensitivity by changing the force transmitted from the conductors to the rotor forging. Varying tightness of wedges and uneven end-winding blocking can cause an asymmetrical variation of axial forces from the field conductors to the rotor forging. Additionally, variations in winding insulation thickness can restrict different conductors' axial movement, thereby also causing variations in the axial conductor forces acting on the forging; again impacting the rotor's thermal sensitivity. Variations in winding insulation may be due to design or manufacture, but more likely can occur from wear, crushing, overheating or other damage to the insulation. Repair of a short or ground may result in unequal insulation thickness, as well as a rotor rewind which did not ensure uniform insulation.

The asymmetry will seem to be an imbalance in the rotor, and in fact it is. However, unlike a typical imbalance, the thermal sensitivity asymmetry occurs only when field current heats the rotor. This asymmetry dissipates after the generator is taken off line and the rotor cools. During start-up of the generator the imbalance from thermal sensitivity asymmetry will also not be present until the field current again heats the rotor. Balance weights may correct this thermal unbalance during operation; however, the rotor will then be truly unbalanced at start-up. Additionally, if the characteristics of the uneven heating change, such as from a field current change or changes of restrictions in the cooling passages, the thermal unbalance will return to some degree.

### ***Rotor Shaft***

Rotor shaft cracking can have catastrophic results on generators. Cracking starts small, almost unnoticeable, and then grows without any indication of trouble. Once the crack reaches a critical size, it can grow rapidly until eventually resulting in shaft failure. Fortunately, until reaching that critical size, crack growth can be slow enough for detection by dye penetrant and other non-destructive testing techniques during scheduled outages.



**Figure 2-12**  
**Catastrophic Shaft Failure**

Keyways, seating surfaces and other machined areas on the rotor's shaft may be stress risers which, when subjected to strain from rotor flexing and vibration, initiate shaft cracking. Additionally, heat shrunk components such as fans and couplings exert extreme pressure on the shaft and especially on nearby stress risers, adding to the strain and the possibility of crack initiation.

Crack initiation is dependent on the presence and configuration of the stress risers. Obviously, most generators do not suffer from potentially catastrophic crack initiation. Similar make and model generators will have similar susceptibility to cracking. However, different vibration characteristics and stresses on the rotor shafts can result in some differences in susceptibility, even for similar machines. Also, torsional vibration and operational events such as negative sequence currents can create forces, which contribute to crack initiation and growth.

Typically generator makes and models, which do not have industry history of shaft cracks, will likely not develop the problem. Makes and models which do have a history of shaft cracking, or those generators which have been subjected to abnormal forces such as from a system fault, should be inspected for crack initiation. Susceptible machines will need periodic inspections until a modification is performed, if possible, to remove or minimize the stresses risers. After a shaft modification, inspections may be less frequent or possibly eliminated; though, at least one inspection should be performed after post modification operation to verify effectiveness of the modification.

Vibration issues can be caused by adding a stub shaft to the rotor. A stub shaft is typically installed to support the collector rings due to modifications on the excitation system. These modifications include replacing a directly coupled rotating exciter with a static exciter; replacing a brushless exciter with a brushed exciter; or replaced a mercury bath collector with a brushed collector.

Usually, OEMs and other experienced service providers can supply and install a trouble-free stub shaft. Great care must be practiced in the design, manufacture and installation of a stud shaft. A thorough vibration analysis of the generator rotor has to be performed to ensure that critical frequencies and other important rotor parameters are not adversely altered by the modification. The stub shaft will alter the rotor's axial, radial and torsional vibration characteristics. Power system stabilizer responses may have to be adjusted to account for the changed torsional vibration characteristics. An inadequately designed and manufactured stub shaft can be very difficult to align and can create generator vibration problems.

### ***Rotor Slot Teeth***

Dovetail cracking has become a significant issue with owners and operators of large generators, as these generators in particular tend to be more susceptible this type of cracking. The middle of the rotors being unsupported and undergoing more flexing than the ends, is more likely to have dovetail cracking. Most of the cracks can be detected when still small, and be readily repaired, if inspections are performed. Causes of dovetail crack initiation and propagation are believed to include fretting on the teeth by the slot wedges, negative sequence current and cyclic generator operation. Some recent analysis and studies indicate that fretting is not a major issue in regards to crack initiation, but rather damage from negative sequence current may be more responsible.

Fretting wear on the rotor teeth at the dovetails' load face has been thought to be a leading cause of dovetail cracking. The slot wedges press tight against the teeth's dovetails; and more so at

speed due to centrifugal force. A rotor being supported at its ends is bowed downward slightly due to gravity with the most deflection at the rotor's middle. Though this bowing or deflection of the rotor is indiscernible to the unaided eye, it is sufficient to cause an increase in the length of the bottom of the rotor. As the rotor turns, points on the circumference undergo lengthening as they pass beneath the rotor's centerline; and then, contraction as they pass above the centerline. Thus the length of the rotor slots and teeth will alternately lengthen and shorten as the rotor turns.

As the teeth lengthen and shorten with the turning of the rotor, the slot wedges held against the teeth's dovetail by the slot contents and by centrifugal force rub against the dovetail surfaces. This rubbing not only causes fretting but also causes alternating stress on the dovetail surfaces. The fretting and alternating stress can eventually lead to crack initiation. Often the resulting cracks initiate at stress risers such as cooling cross-slots. Once initiated, cracks often grow slowly until a critical size is reached, then the crack can grow rapidly through the rotor tooth.

Crack growth continues by the actions of rotor flexure as it rotates. Additionally, forces from thermal expansion and contraction in both the conductors and the forging, act in the development and spread of the cracking. Previous stresses from negative sequence current and generator motoring also contribute to the initiation and progression of the cracking. The propagation and the critical crack size are unique to each machine. The design of the rotor, the operational parameters and the history of the machine impact crack growth.

Cyclic operation of the generator such as two-shifting, starting up the generator for part of the day to handle high grid loads and then shutting down for the rest of the day, can hasten crack development. Being on turning gear, speeding up when starting, and spinning down when stopping may produce more fretting by the wedges. At the lower speeds, the wedges are not pressed by centrifugal force as tightly against the dovetails as when at speed. The wedges, therefore, at lower speeds are freer to move against the dovetails.

Another factor in dovetail crack development is believed to be wedges made of steel. Part of the recommended solution to limit dovetail fretting is the replacement of the steel wedges with ones made of aluminum. Aluminum wedges being softer than those of steel, does not impart as much fretting stress on the dovetails. So far units employing aluminum wedges have experienced significantly less dovetail fretting. Of course, aluminum being non-magnetic, a detailed analysis of the field's electromagnetic characteristics and the impact of the aluminum wedges will need to be performed, as well as a mechanical analysis. Not all wedges will typically need to be replaced with aluminum wedges; typically the middle two-thirds of the rotor will benefit the most from wedge replacement.

Besides fretting damage during operation, slot dovetails can be and have been damaged from installation of the slot wedges. Care must be exercised with installing the wedges as with other components of the rotor. Whether the wedges are oversized, are jammed from slot packing or just poor craftsmanship, the damage is the same. The corners of the steel wedges can gall the surfaces of the dovetails. Damage to the dovetails, if not immediately repaired, will be a stress riser, which may initiate dovetail cracking.

### ***Rotor Baffle Assembly***

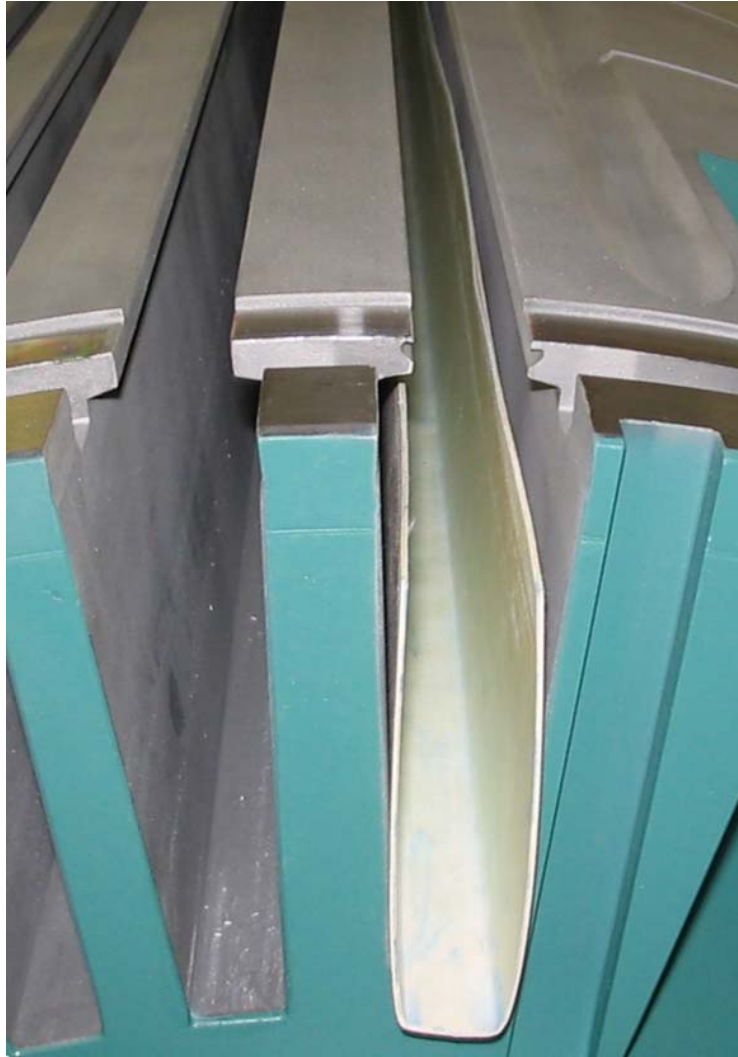
The rotor baffle assemblies are located at the ends of the forging and are designed to direct cooling hydrogen to the appropriate areas. Not all rotors utilized baffles. On the rotors utilizing baffles, the baffles can be subjected to vibrations, which may cause fatigue of the assembly components and damage from loose rotor components and debris. Though not many instances of damage have been found in comparison to number of units in services, cracks and other damage have been discovered during inspections. Typically, inspection and nondestructive testing of the baffle is recommended during generator outage disassembly. Usually baffle assembly inspection requires retaining ring removal for full access to the assembly.

### ***Slot Liners***

As previously discussed in this chapter, the slot liners are subjected to forces from rotor flexure, and the thermal expansion and contraction of the conductors. These forces may in some instances be sufficient to move the slot liner axially. Liner movement or migration leaves the liner in the wrong position, which may block cooling passages and may expose parts of the slot wall to the field conductors.

The ends of the slot liners are subjected to more damage due to being at the rotor ends which typically have conductor movement and vibration. Additionally, the ends of the slot liners can be stressed from liner movement and being pressed against other components; thus be damaged.

Fretting damage to the slot liners can occur from rotor flexure and conductor movement, even if there is no liner movement. Relative movement of the rotor and conductor wear on the slot liner and produce fretting damage, which may lead to liner cracking. Poor practices during rewinds and during slot wedge installation may damage the liner. Cracked liners can be more susceptible to migration and because the liner is ground insulation, cracking may lead to field grounds.



**Figure 2-13**  
**Slot Liner**

**Courtesy of Portland General Electric**

### ***Rotor Fan***

The generator cooling rotor fan is typically robust and not usually susceptible to damage. Not all rotors employ fans, relying on the rotor cross-slots to move the cooling gas. Damage may occur to the fan during rotor removal and installation, and during rotor maintenance. Rotor vibration may lead to fatiguing the fan's metal if excessive. A damaged fan can lead to increased vibration, and if the fan's damage is sufficient the fan may throw pieces which will likely severely damage the generator.

## **Slot Wedges**

The slot wedges hold the field conductors in the slots against centrifugal force and may also be designed to direct cooling gas into the slots. Due to centrifugal force, the slot wedge must handle significant stress. The wedge areas adjacent to the dovetails are the most stressed and often where cracks initiate. In these areas, one on each side of the wedge may be stress risers where the wedge is machined to fit in the dovetail. Rotor flexure and conductor movement can contribute to crack initiation and propagation.

A failed wedge can cause severe damage to both the stator and rotor, and even cause catastrophic generator damage. Fortunately, wedge cracking is rather uncommon and actual wedge failure is rare especially when wedges are periodically inspected.

Centrifugal force will hold the wedges tightly in the slot dovetail during operation. However, at low speeds during start-up, shutdown and while on turning gear, the slot packing has to hold the wedges in position. Excessive packing clearance can leave the slot wedges relatively loose and possibly lead to fretting against the dovetail surfaces. Excessive packing clearance can also lead to movement of the conductors and other slot contents, causing fretting wear and distortion of the conductors. Movement of the wedges can restrict cooling, as cooling passages in the wedges may no longer line up with the passages in the slots and in the rotor forging.





# 3

## OPERATIONAL ISSUES

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Operation of the generator rotor and field is designed to require almost no action by the plant operators. An automatic voltage regulator controls the field current to maintain a desired generator output; relays and other devices ensure protection from abnormal conditions and transients; generator start up, synchronizing and shutdown may be automatically controlled in newer and retrofitted plants. Temperature, voltage, current, vibration and possibly flux instrument monitor rotor condition though seldom require operation attention. However, the rotor is a vital link in electrical power production. Failure of the rotor can cost a utility weeks or months of lost revenue.

### Operating Mode

Operational issues concerning generator rotors involve the modes, in which the generators are operated, and the conditions and transients to which the rotors are subjected. Modes of operation include base load, peaking and mid merit. Peaking and mid merit duty actually can place much more stress on generator rotors than base load operation. The on and off cycling of generators subjects the rotors to start up and shutdown stresses which increase wear and strain on rotor components. Additionally, being on turning gear can also increase movement and flexure of components that would normally be securely held in place by centrifugal force when the generator is on line. Two shifting, which involves running the generator during peak load times of the day and then shutting down for the remainder of the day can be most stressful on the rotor by maximizing the start up and shutdown cycling.

During generator operation, centrifugal force presses conductors and other slot components against the slot wedges, and this tends to secure the components. Some flexure of the rotor, particularly at the rotor's middle, occurs due to gravity and spinning of the rotor. Typically the flexure is barely noticeable and inconsequential to the rotor. The field current is relatively stable and the ohmic heating of the conductors is constant and not causing thermal expansion or contraction.

During start up and shutdown the rotor is not at full speed and centrifugal forces may not be great enough to secure components. Even though the start up and shutdown time intervals are relatively short, much of the wear and fatigue on rotor components can occur during these intervals when the components are not fully secured in position. Thermal expansion and contraction of the conductors and other components occurs during start up and shutdown, causing stress, movement and wear of these components. Besides wear, the thermal expansion

and contraction can produce uneven or unsymmetrical forces on the rotor, and can further fatigue connections, links and supports.

During turning gear operation, there is insignificant centrifugal force on the rotor. Still the rotor's middle will flex as it turns due to gravity. Certain rotor components, without centrifugal force securing them, can rub; thereby creating fretting and fatigue. Insulation wear and copper dusting are examples of the degradation that can occur mostly while on turning gear. Since some units may be on turning gear for extended periods of time, possibly more time on turning gear than in operation, significant more wear can occur.

Plants with generators known to be prone to significant wear while at low speeds, including when on turning gear, should avoid extended periods of time while on turning gear as much as possible. Otherwise, the plants should schedule frequent inspections to check for rotor wear problems; possibly yearly inspections until a confidence level is reached that inspection frequency can be changed. Plants which are not sure if their rotors are susceptible to low speed problems, should evaluate past inspection results and operational history; and determine an inspection frequency that will adequately forewarn of potential rotor trouble. These plants too may need to schedule frequent inspections at first, and as more inspections are performed, adjust the inspection frequency as needed.

The cyclic duty many generators have to undergo cannot be avoided in almost all cases. Economics and grid loading dictate cycling these units on and off. In fact, many of these plants were designed and built as peaking and mid merit units. While the cycling of the generators cannot be avoided, it is important for the owners and operators of these units to realize the degradation that can occur to the rotors. Increased maintenance and inspections frequencies may be necessary to maintain generator reliability. Repairs and refurbishments to the rotors are expenses that may need to be considered in determining the cost to operate and maintain the plants.

## **Operation with Shorted Turns**

By some estimates more than half of all rotors in service have shorted turns. A small number of short turns usually do not create apparent operational problems with the rotor. With one or a few shorted turns, the imbalance in resistance between the poles is typically not sufficient to produce uneven rotor heating and the subsequent vibration. Also, the small decrease in amp-turns may not produce a noticeable increase in field current, and the change in impedance may not always be detectable with electrical testing.

However, a shorted turn even if unnoticeable can lead to further degradation in the rotor. Usually a short is not a solid low resistance current path. Heat from current flow through the short's resistance may produce conductor damage. Furthermore, the heat may degrade nearby insulation causing further shorts; and may damage the slot liner creating the potential for a field ground. Arcing from a loosely connected short will increase the amount of heat damage produced.

Some shorts and grounds may only be present when the generator is in operation. Centrifugal loading and thermal expansion may press conductors sufficiently to make contact only during operation. Nevertheless, these intermittent shorts and grounds can still produce the degradation described in the previous paragraph. Furthermore, since these intermittent shorts are usually very loose connections, the resistive heating and arcing from them will likely be greater than from a more solid short.

While a low number of shorts may have no apparent operational effects, the rotor should be visibly inspected whenever it is removed during generator maintenance, as well as having periodic electrical testing performed. Although, one or a few shorts may not be detectable, trending the electrical test results, as well as the field current and temperature will help detect and identify further degradation.

Consideration should be given toward the installation of air gap flux probes and a monitoring system. Utilities have reported good success with identifying shorted turns with the system. With the air gap flux monitoring system, preparation for repair can often be accomplished in a timely manner for the next available schedule unit outage. The monitoring system can trend the field condition while the generator remains in operation providing assurance of continuing operation or warning of increasing degradation.

While operation with a shorted turn is not ideal, it may be the only practical and economical solution until the next available outage. It can be a difficult decision to continue operation with a known defect that may degrade further. The likelihood of significant damage is not very high with a single shorted turn, though the number of stops and starts should be minimized in order to reduce stresses on the winding. Operation with a field ground, a significant number of winding turn shorts causing noticeable vibration or increased field current, or a degrading trend is not recommended; and the unit should be removed from service as soon as practical.

## **Operation with Rotor Cracks**

Operation with known flaws in retaining rings, top teeth, dovetails and other areas is definitely not recommended due to the risks of catastrophic generator failure. However, the economics of power plant operation may require putting the unit back into service before a repair can be implemented. Even though the generator must be in an outage to identify cracking, it may not be economically feasible to extend the outage, especially since services and equipment to affect the repair may require a long lead time. Obviously the cracking or flaws must be rather minor, or else the unit should not be allowed back into service despite the economical costs.

The generator OEM must be contacted for advice on continuing operation with a known defect, and a request should be made to have the cracking inspected and assessed. If the OEM is unavailable, a reliable experienced service provider should inspect the rotor and advise on possible courses of action.

Plants that have successfully continued to operate with known flaws and cracks have an increased inspection frequency to ensure a severe degradation is not occurring. They also maintain records of inspection results to trend the progression of degradation and provide some assurance of continued operation.

A better option than continued operation of the generator when a long extension of an outage is not possible is to secure a replacement rotor. Utilities have acquired and maintain a spare rotor by themselves or with a consortium of other utilities having similar generators. Others have located and either rented or purchased a replacement rotor when needed. Installing a replacement rotor will still extend the outage; however, it will not typically be as long of an extension as a repair may require, and it will provide a known good rotor to assure reliable generator operation.

## **Contingency Planning**

An unplanned generator outage or outage extension can be extremely expensive to a utility. Replacement power costs and lost revenues for unscheduled outages are significantly higher than that for scheduled outages. A failed rotor, even without causing collateral damage to the generator, can take weeks, even months to repair. By having parts, materials, and prepared plans of action and procedures available, the length of a force outage may be significantly reduced.

Obviously it will not be cost effective or practical to have a contingency set up for every failure scenario. However, identifying probable failure modes from industry experience and from the results of generator tests and inspections, a plant can implement a cost effective contingency plan. One such failure scenario could be shorted turns in the field winding. Shorted turns are not uncommon and while not likely to cause an immediate shutdown, they can necessitate an unscheduled or an extended outage to be repaired. Having the material and procedures available can significantly reduce the length of the repair outage. Additionally, having reliable vendors identified who can reliably supply materials, tooling and services when needed, will save additional time.

# 4

## INSPECTIONS AND MAINTENANCE

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In today's competitive energy market, plants are burdened with budget cutting and the continuing need to reduce costs. Additionally, the average age of power plants has been increasing. With fewer newer plants, the older ones are called upon to continue operation often beyond design life. Also, with increasing age, plant equipment such as the main generator, may begin to experience end of life deterioration and failures. Often every dollar or other monetary unit spent has to be carefully accounted for and proven to show an effective return for the expenditure.

Assuring the integrity and reliability of the generator needs the integrity and reliability of the rotor maintained and enhanced to the extent practical. As mentioned in this report and other literature, deregulation of the electric power industry has caused budget cutting and maintenance reduction at many facilities. Power companies are looking to ways of reducing maintenance and operating expenses while still maintaining equipment reliability and availability. Plants are under pressure to cut maintenance activities, run for longer times between outages, and reduce outage durations.

Some utilities may have the view that the inspection recommendations from OEM and other experts may be too conservative and do not warrant the expense for removing the rotor more often than the plant desires. Others may believe that their generator rotors have not experienced harsh enough duty to warrant the recommended inspections. However, the risk of an extended forced generator outage and the cost of such an outage will greatly exceed the cost of performing the recommended inspections. Without a strong and realistic technical reason to delay rotor inspection the risk for not performing an inspection can be too high.

An important part of maintaining the generator rotor is assessing the rotor's condition. Inspections and tests identify flaws and defectives at an early stage. Early identification of problems allows for remedial actions before minor flaws and defects can worsen into potentially dangerous and catastrophic failures. Though remedial action may at times require extensive rework of the rotor, its components, and an extended outage; the expense of the rework and outage are well less than that of a major failure. To aid utilities in the performance of rotor maintenance and repair this report is prepared.

This report is a compilation of Lessons Learned and Best Practices submitted by utility personnel and service providers who have experience and expertise with generator rotors and generator maintenance. The intent of this report is to provide the reader the benefit of the experience from peers in the electric power industry; experience which the reader can use in developing and improving maintenance and operating practices in his or her own company. This report is not

intended nor can be an all inclusive guide to generator rotor maintenance with the latest state of the art technologies and practices.

Predictive and preventive maintenance provides the means to ascertain a rotor's material condition and affords an opportunity to take prompt early action if needed to forestall major rotor and field problems. Obviously properly maintaining the generator rotor will extend the service life of the generator and minimize power degradation and outages. An improperly maintained rotor could be subjected to minor flaws, which over time will worsen if neglected.

While tests, inspections and periodic maintenance cannot guarantee extended rotor and field life, they do provide assurance of continued generator operation for the next operational cycle. Some even say that a reliable estimation of remaining life is not possible; still the predictive and preventive tests, inspections and tasks are essential towards preventing major or even catastrophic failures from developing. Analyzing and assessing information from past inspections and test, operating events and data, industry experience with similar units, recommendations from the OEM, and any current inspections and tests are critical toward ensuring the reliability of the generator rotor during the next operational cycle. For further detailed information on rotor maintenance, readers are encouraged to review the EPRI report "Optimized Maintenance of Generator Rotor" (reference 7).

## **Off Line Electrical and Tests**

Field winding problems include shorts, grounds and bad connections. Most winding problems can be detected by periodic electrical testing, though some conditions may require some severity to be detected. For example, a shorted winding turn may not be detected; as the short is often a high resistance connection that may not significantly change the total measured winding resistance. Additionally, most electrical testing has the limitation that it can only be performed during an outage. Thus degradations occurring during operation cannot be detected and assessed by electrical testing until an outage. Complicating matters more is that some grounds and shorts may only occur at speed. Centrifugal forces and thermal expansion may cause a fault that clears when the generator is shut down and cooled.

However, this observation is not intended to indicate that electrical testing is not beneficial. The relatively low cost of the testing versus the high cost of the problems of which it can forewarn, provides a high benefit to cost ratio. While still performing periodic generator electrical testing, plants need to be aware of testing limitations and also adopt other technologies to augment the electrical testing. Heat sensitive paint or tags, air gap flux monitoring and field ground detection relays are all methods that can be employed while the generator is running, and provide additional critical information on the condition of the field.

The EPRI report, "Tools to Optimize Maintenance of Generator-Excitation System, Voltage Regulator and Field Ground Protection" (Reference 6) provides more detailed information on electrical testing. Readers are urged to consult that report for further information on field testing

and maintenance. The following is a brief overview of the common field electrical tests typically performed at each maintenance outage.

### ***Insulation Resistance***

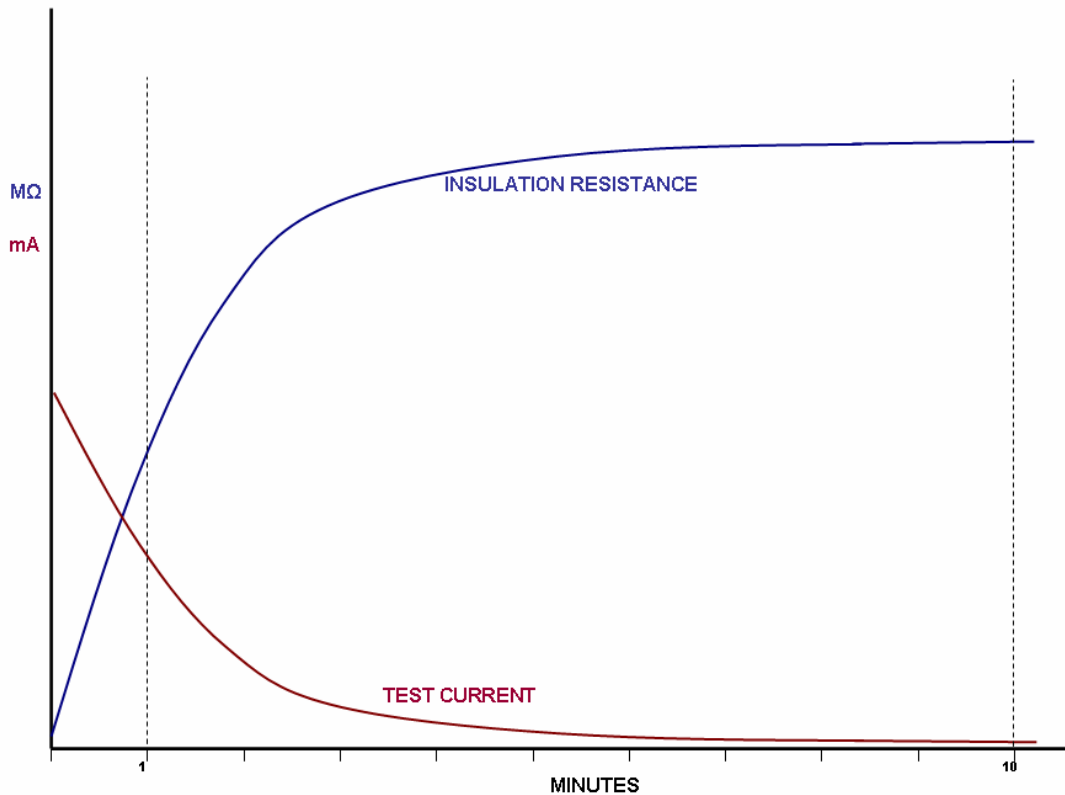
Insulation Resistance (commonly referred to by the trade name Megger) consists of applying a fixed DC voltage between the field winding and rotor forging. The applied voltage produces a small current through the winding's ground insulation which is proportional to the insulation resistance by Ohm's Law. Typically, insulation resistance meters are scaled to read resistance instead of current. IEEE 43 provides recommendations for testing insulation resistance, including test voltages levels and acceptance criteria.

Low insulation resistance indicates possible insulation trouble. Moisture and contamination are often causes of low insulation resistance. Cleaning the exposed windings along with the rest of the field circuit, such as collector rings if applicable, can help improve the resistance reading. Additionally, for windings where moisture is causing low readings, applying a low heat, blowing dry air, or applying a DC current to the windings, should dry the windings and improve the resistance measurement. Any applied current to dry the winding must be limited to well under the winding's ampere rating.

In addition to problems with moisture and contamination, the insulation resistance test is useful for detecting other problems including: insulation degradation, such as abrasion wear and cracking; copper dusting, where applicable; and shifted or displaced insulation.

### ***Polarization Index***

The polarization index or PI test is often performed in conjunction with the insulation resistance test. A PI test performed by applying the insulation resistance test voltage for 10 minutes and taking insulation resistance measurements at 1 minute and 10 minutes. The PI is equal to the ratio of the 10 minute reading over the 1 minute reading. Unless the leakage current is abnormally large, the PI should be greater than 1. For most windings the value should be greater than 2. However, in cases where the insulation resistance is very high, more than 5,000 megohms, the PI reading is considered unimportant and a low PI reading with high insulation resistance is acceptable. IEEE 43 also provides guidance on performing and analyzing PI test result.



**Figure 4-1**  
**Insulation Resistance Over Time**

### ***Winding Resistance***

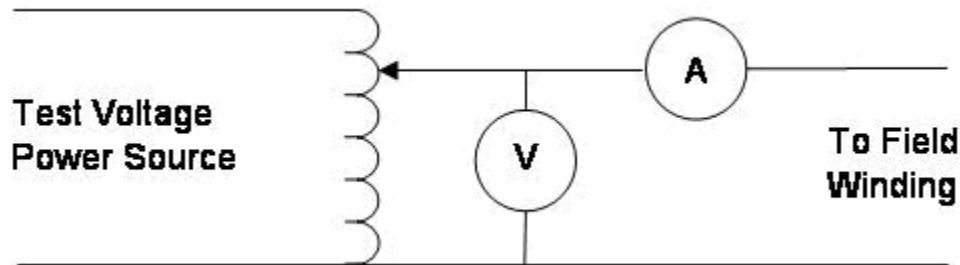
The total field winding resistance measure from one polarity to the other should stay fairly consistent from one testing cycle to another. Some variation in resistance due to winding temperature will occur and have to be accounted for in analyzing the test results. Standard formulas exist to correlate winding resistance readings to resistance values at a standard temperature. The winding resistance measurement verifies winding continuity, identifies possible bad connections, and possibly detects short turns. IEEE standards 115 and 118 provide recommendations for resistance measurements.

### ***Winding Impedance Test***

The winding impedance test is typically better than a winding resistance test for detecting shorted turns. With the impedance test, an AC test voltage is applied to the winding in incremental steps. The test voltage is applied in 4 or 5 incremental steps up to a final test voltage of 120 to 150 volts. The current is measured after it stabilizes at each step. The theory of the test is that at the lower voltage values, current will not flow through a short between turns, as typically the shorts are not solid electrical connections. However, at the higher test voltages, the turn to turn voltage can be significant enough to bridge the short. Once the short is bridged, the



turn is effectively removed from the winding, and the winding impedance decreases allowing more current to flow. While a plot of the test voltage versus current may not be strictly linear, any abrupt change in the plot, indicating an abrupt impedance change, is an indication of a turn to turn short.



**Figure 4-2**  
**Simplified Impedance Test Diagram**

### ***Recurrent Surge Oscillography***

Recurrent Surge Oscillography (RSO) can be used to identify and locate faults in the field windings. RSO is a variation of the Time Domain Reflectometry (TDR) method to locate faults in cables. The field must be isolated from the rest of the excitation circuit in order to perform an RSO test. The RSO test set is connected to the winding ends and identical pulses are injected into the field from both ends. If the field winding and its connections are in good condition, the reflections from both pulses should be identical. A ground condition or an interturn short causes a partial pulse reflection from that location that can be detected by the test set. The timing of the reflection indicates how far into the field winding the fault is located.

Special RSO test equipment is required to perform this test, as well as training for the technician who will conduct and interpret the test results. Many plants may not have the equipment or in house expertise for this test. However, a service shop or a testing company with the equipment and expertise can be brought in during an outage to perform the RSO test, along with other tests and services.

### **Online Rotor Monitoring**

Various online monitoring techniques that provide indication of rotor condition are available to plants. Some are common in plants and are typically utilized; while others, though beneficial, are not yet commonly employed. Commonly used online methods to monitor rotor and field conditions include: ground detection relays, vibration monitoring, field temperature monitoring, and field voltage and current monitoring.

## **Field Ground Detection**

The field ground detection system is pretty straight forward. The detector, usually a ground detection relay, applies a small voltage between the field circuit and ground, and senses the current produced by this voltage. If the ground insulation of the field circuit is good, a negligible amount of leakage current flows. Deterioration of the ground field insulation allows more current. If the current exceeds a certain calibrated value, the detector actuates to alert the plant operators of a possible grounded field circuit. Many generators have a continuous ground detection system wired directly to the field excitation circuit, upstream of the collector rings and brushes. Brushless generators may still employ a brush specifically installed to field ground mounting, and which is periodically applied to check for field grounds. The ground detection system, should be tested and verified periodically through the application of a test ground, typically designed and built into the detection circuit.

A detected field ground can have a number of causes including: degraded ground wall insulation; copper dusting; contamination; and may even be due to trouble off the rotor, a ground on the excitation circuit leading the generator. A single ground by itself is not a significant problem, in that the generator field is normally an ungrounded circuit. The single ground is not a completed path for the field voltage and thus does not produce a fault current. The concern with field ground is the possibility of a second ground completing the fault path. Depending on where two or more grounds occur in the field winding, a significant and damaging fault current can flow.

Utilities implement different procedures for response to the detection of a field ground. Some require taking the generator off line as soon as possible. Others require taking the generator off during the next period of low load within a few days. Still others may permit continued operation for longer periods of time, until a convenient time for an outage is reached. All plants have to have a careful risk assessment of their intended actions, balancing the risk of potential generator damage and lost generation against lost revenues and also grid effects from an outage. As has been mentioned numerous times in this report, the OEM and experience service providers' recommendations, as well as that of experience plant personnel, must be consider in determining the course of action. Additionally, insurers, grid operators and other regulatory entities may have requirements that need to be followed.

Upon receipt of a field ground, plants should verify the presence of the ground and assess the nature of the ground. Typically the ground detect circuit has a test point at which the detector's ground current can be measured. This test point may be designed into the circuit or have been designated procedurally as a wire to be lifted. Either way, an ammeter measures the ground current, and technicians and engineers can determine the amount of ground current. This provides verification that the ground detector did operate properly and also verifies whether there is a weak or a strong ground present. Additionally, by measuring the voltage at the detector's field wire to ground, it can be ascertained whether the ground is on the positive or negative side of the field. Some detectors may have voltage and current instruments built in to aid in troubleshooting and assessing the ground.

Some visible inspection can be performed with the generator still online to determine if the ground is due to a fault off rotor, though personnel safety issues must limit the extent of inspection. Where applicable and possible, switching off diode banks and other portions of the excitation circuit may be done to try to locate and isolate the ground. The EPRI report, “Tools to Optimize Maintenance of Generator-Excitation System, Voltage Regulator and Field Ground Protection” (Reference 6) provides more detailed information on ground location and readers are urged to consult this report.

### ***Field Voltage and Current***

The field's voltage and current provides insight into how well the field winding is capable of maintaining generator excitation. Field winding troubles such as shorted turns and poor electrical connections will cause changes in either the voltage, current or both. While not possible to directly monitor field current on some generators, monitoring the excitation system's output for these machines can indirectly provide similar insight into the field's condition.

Whether monitoring field voltage and current directly or indirectly, these parameters should remain consistent for a given generator output. Other field circuit problems can also impact current and voltage including brush problems, diode and fuse failure, poor lead termination and instrumentation errors. However, variation in the current or voltage of a particular generator output still can indicate a problem whether in the winding or else where in the excitation system.

Field voltage and current monitoring involves periodic review of recorded values for variations which not due to generator loads or other acceptable influences. The review should also consist of a comparison with past data to detect slow increasing changes. The periodicity of the review is often once per week, though some plants may choose to employ either a shorter or longer period. Based upon their own experiences and needs, plants should decide the scope and frequency of review; but also include in the decision process OEM and service provider recommendations, and any requirements of insurers and regulatory groups. Additionally, the field voltage and current should be checked once per shift to note any sudden or abrupt variation from normal values.

### ***Field Temperature***

The field temperature monitoring system typically reads the field voltage and current, and computes the field winding temperature. This computation is based upon Ohm's Law to determine electric resistance and the temperature coefficient of resistance for the winding copper in order to provide an average temperature reading of the field winding. On generator employing collector rings and brushes, the voltage and current transducer are wired directly to the excitation circuit upstream of the brushes. Brushless generators may employ a wireless transmitter mounted on the rotor to relay temperature data.

The field winding temperature should be checked periodically during the shift to note abnormal temperature changes. Often an alarm may be used to alert the plant's operator if the temperature

rises above a predetermined value. Additionally, field temperature should be trended weekly or at most monthly to note gradual variations that can be indicative of problems.

Field problems which the temperature monitoring system may indicate include bad electrical connections, high field current, clogged or blocked cooling passages, fouled cooling heat exchanges, and other cooling system issues. The temperature monitor shows an average field temperature and does not indicate localized heating. Plant personnel need to be aware of this limitation as well as the capabilities and usefulness of the monitor. Another method employing heat sensitive material is useful for identifying localized hot spots and is discussed later in this section.

Besides showing the average field temperature, the temperature monitor if continually recording the temperature reading can show certain brush and field circuit problems. Since the temperature monitor is actually sensing voltage and current, any variation in voltage causes a variation in the computed temperature value. The voltage regulator and inductance of the field winding will act to keep a constant field current to maintain generator output. Intermittent connection problems within the field circuit, including the brushes if applicable, will cause voltage to spike which can show as a spike or a series of spikes on the temperature recording.

### ***Vibration Monitoring***

Certain rotor and field problems can manifest themselves as rotor vibration. Significant cracking can create asymmetric stiffness of the rotor, causing uneven flexure of the rotor from its weight as it rotates. Shorted turns create uneven current distribution thus producing uneven rotor heating. This uneven heating in turn causes uneven thermal expansion of the rotor and thereby producing a slight bow in the rotor. Additionally, shorted turns produce uneven magnetic flux in the field winding, which causes a varying force on the spinning rotor.

Generators are typically equipped with vibration monitoring. Significant vibration levels on most generators will cause the monitors to alarm, thereby alerting the operators of high vibration; more severe levels will cause the monitors to trip the generator off line. Below the vibration levels which alarm and trip, there can exist vibration signals which indicate possible rotor problems that should be investigated. Routine periodic collection and analysis of the generator's vibration signals is beneficial to detecting rotor and field problems before they become severe.

Vibration data collection for periodic analysis may be performed with installed instrumentation or with probes placed temporarily for data collection. Not all plants have installed vibration instrumentation, and thus have to use temporary probes. Periodicity of the data collection and analysis will vary with equipment condition, plant experience, results from past analysis, and industry experience with similar units. Typically a period of once a month for data collection and analysis is sufficient. Generators which are experiencing problems, or have a history of trouble, may require more frequent monitoring in order to trend the equipment condition and forewarn of severe equipment degradation. Generators in good condition may have a longer period between analyses, but generally no longer than once a quarter.

## Torsional Vibration

Increased attention is being paid toward the effects of torsional vibration on the rotor. Torsional vibration produces a twisting of the rotor; some experts feel that this twisting may significantly impact the rotor forging, the retaining rings, the rotor shaft and other components. Back and forth twisting can create metal fatigue over time possibly leading to cracking and eventually failure. System transients, such as line switching, heavy loads coming on and going off, nearby power generation and faulty power system stabilizers can induce torsional vibration or oscillations in a generator.

For most generators, torsional vibration is rare and does not present a problem. However, plants need to know if their generators may be or have been subjected to torsional vibration. Because of unawareness of the problem in the past, and the sophisticated equipment that was required, torsional vibration monitoring was not commonly practiced. A number of plants have installed monitors in recent years, as the equipment has become more practical and economic. The installation of a torsional vibration monitor can often now be beneficial; detecting the presence of torsional vibration and providing a measurement of the severity if the vibration exists.

### ***Online High Temperature Detection***

Online rotor temperature monitoring systems beyond those systems employing field current and voltage can be quite beneficial in early detection and identification of field hot spots. Formulations with specific chemical compositions can be applied to areas on the rotor and other parts of the generator.

Gen-Tag is the brand name of one particular product using a specially formulated paint to detect generator hot spots, on which information was supplied in the development of this report. If other product lines utilizing the same or similar technology come on the market, this report does not recommend one product over another; but leaves it to the end users to identify the best one for their specific applications.

The specific composition of an application is designed to release a signature gas above a certain temperature into the generator's cooling gas. A detector samples the cooling gas, monitors for traces of the signature gases from the various applications in the generator. A key advantage to this system is the ability to detect localized heating of the field. Detecting rotor localized hot spots provides an indication of a winding short or poor connection. A field temperature monitor relying on the field current and voltage can only provide an average field winding temperature indication.

An example of a signature chemical for detecting field hot spots is dihexyl amic acid in a blue alkyd paint formulation which is applied to the rotor surfaces.

## ***Air Gap Monitor***

Several of the responses to the surveys used in the preparation of this report, recommended the use of online air gap flux monitoring. Air gap flux monitoring has been employed in large motors and generators for a number of years, and has proven beneficial in not only detecting winding faults, but also has proven useful in the analysis and assessment of machine problems.

Air gap flux probe installation requires rotor removal and the removal of some stator slot wedges. The flux probes are installed in the stator slot and sense the magnetic field in the air gap between the stator and rotor. Installation obviously requires a generator outage with rotor removal and can increase the outage work scope, especially if stator slot wedge work activities are not planned for the outage. However, the additional work to install the flux probes can be well worth the cost. Detection of small problems during operation, particularly when no other detection means are available can save expense and time in determining causes of operational issues and problems, such as rotor vibration. Identifying and ascertaining field problems during operation can be an advantage in planning and implementing corrective actions for the next outage.

Usually the air gap flux probes are connected to a monitoring system that allows viewing and analysis of the air gap flux signals. A number of users reported checking and analyzing monitor readings periodically, typically once a week, to ensure no field degradation. If an abnormality is found, the flux monitoring system signals are analyzed to determine the nature and extent of the problem. The frequency of checking and analyzing is increased to determine if the degradation is worsening or is being stable. Several users reported that due to the success of installation and utilization of the air gap flux monitor in one generator, they have installed, or plan to install, the monitor system in other units.

## ***Rotor Inspections***

Rotor inspections mainly required removal of rotor from the generator, and can require some disassembly. It can be possible to perform very limited inspections without rotor removal to provide some level of confidence in the rotor's condition. A limited inspection is not recommended for replacing a full inspection, but may be performed to provide an indication of rotor condition until an outage when the rotor can be removed. The main areas of concerns to most are retaining rings, dovetail areas, and end teeth tops. Other areas may be of more concern to some plants with certain generator models. The OEM and experience from other units with similar generator can provide beneficial information on required inspections.

## ***Retaining Rings***

Several practices regarding inspecting and examining retaining rings were supplied from utilities, and service providers. While these practices varied somewhat in frequency and content, there were similarities that show a general set of practices. These practices for examining 18Mn 5Cr retaining rings at five to ten year periodicity during outages include the following tasks:

- Visual Inspection
- Dye Penetrant Inspections
- Eddy Current Inspections
- Assessing and analyzing defects and flaws

The area around grooves, holes and other stress concentrators on the retaining rings should receive more attention during inspections, as these areas are most likely to produce stress related cracking and flaws. This is not to say that other areas should be neglected nor receive less than adequate attention, as cracking and other flaws may still occur in these other areas. Also, the centering or balance rings used for rotor mounted retaining rings need a thorough inspection whenever the retaining rings are removed. Particular attention should be paid to the locking key or ring grooves, and other high stress areas on both the retaining ring and centering rings.

### Visual Inspection

The retaining rings do not necessarily have to be removed if there is no indication of defects or moisture. However, as always the OEM guidance and advice from experienced service providers should be heeded in regards to removal and examination of the retaining rings. Visual inspection of the rings should be thoroughly and carefully performed on all accessible surfaces, including borescope inspection of the interior surfaces if possible. Any defect, corrosion, signs of moisture and other flaws must be documented for further evaluation.

Surface coatings, such as varnish, will make visual inspection more difficult and require more thorough examination to locate ring problems. Consideration may be given to removal of surface coating to allow for better inspection of the ring surface; though coating removal should be done only after consultation with the OEM. If the coating is to be removed it should first be inspected for moisture indications, and obviously removal and cleaning agents must not contain water.

Moisture indications, and new or worsened defects and flaws, can be reasons to remove the retaining rings for thorough interior inspections. Though a costly and time consuming process to remove the rings; avoiding the risk of a catastrophic generator failure is well worth the effort. The advice of experience utility personnel, the OEM and service providers should be given high value in the determination of whether to remove the rings or not. With indications of moisture and flaws, it is better to err on the side of safety and remove the rings for further inspection.

### Dye Penetrant Inspection

Fluorescent dye penetrant inspection should follow the visual inspection. The dye penetrant inspection can identify cracks, pits and other defects too small for visual inspection. A fluorescent dye is better for detecting small cracks and pits. Any surface coating such as varnish can mask cracks and pits, and will need to be removed for the inspection. The precautions in the previous section on visual inspection will need to be followed regarding coating removal.

Pitting or cracks found in a linear array or in groups require special attention, as these may indicate on going stress corrosion cracking. All findings from the inspection should be carefully documented; and if possible, photographed. If it is determined that the defects and flaws found are acceptable for continued operation, documentation of the current findings will provide a baseline for future inspections to better ascertain if the flaws are growing or worsening.

During ring interior surface inspections particular attention should be paid to critical areas. These areas are locations in which moisture can be trapped, such as grooves, and locations containing stress raisers, such as grooves and slots. Additionally, the shrink fit area of the ring is always under stress when mounted on the rotor and should receive special attention.

### Eddy Current Inspection

Eddy current inspections should follow the visual and dye penetrant inspections. Flaws undetected by the other inspections may be found by the eddy current inspection. Additionally, the size and depth of cracks and pits found by the visual and dye penetrant inspections may be determined from the eddy current test results. Determining the dimensions of the flaws is invaluable to ascertaining whether continued operation is acceptable, and also provides baseline data for future inspections. If the flaws are too severe to allow continued operation, determining the size of the flaws provides valuable data for guiding the rework needed to be performed to repair the rings.

For further analysis, if needed and for baseline data, the inspection results should be recorded and stored. The inspection results should be evaluated to determine the nature of any defect and determine the acceptability of the rings, or whether a repair or replacement is required. Expert personnel, the OEM and experienced service providers should be consulted to determine ring condition if needed.

### Ultrasound Inspection

Some companies reported trying ultrasound testing to further inspect the retaining rings. Ultrasound has the advantage of seeing through the material, potentially sensing defects on both the exterior and interior surfaces as well as inside the material. Phase array ultrasound can provide improve capabilities sweeping through the material at various angles and covering more volume in a shorter time.

Others have reported no success or limited success with ultrasound testing of the retaining rings. Difficulties arise from the coarse grain structure of 18Mn 5Cr stainless steel which can scatter the ultrasound waves masking potential flaws, and produce inconclusive results. The complex geometry of the retaining rings further complicates the inspection, especially area around grooves and slots where stress related flaws may be more probable.

The results of the surveys conducted for this report indicate that present ultrasound technology is not very feasible for examining the 18Mn 5Cr retaining rings. This does not rule out ultrasound



technology and techniques being developed to better inspect retaining rings; nor does it mean that some plants may not find some benefit in the present technology for inspecting their specific rings.

## End Wedge Gap

Faults, load unbalances, switching transients and other operational occurrences produce negative sequence currents in the generator stator which, in turn, induces current flow around the circumference of the rotor. These induced currents travel across the surface of rotor forging and take paths through slot wedges and the retaining rings. Current flow between the slot wedges can produce arcing and high heat as the path between the slots and rings is not typically a solid electrical connection.

To prevent current flowing between the wedges and the rings, many generators are designed to have a gap between the slot wedges and the retaining rings. Rotor flexure at low speeds and on turning gear may cause wedge axial movement or shifting, closing the gap wedge and retaining ring gap. This shifting and closing of the gap allows for possible wedge to ring current flow during negative sequence and motoring events, with arcing and resistive heating.

Not all generators have a designed wedge to retaining ring gap; some rotors are designed to have a good electrical connection by a tight fit between the wedges and the rings. In these rotors, the tight ring to wedge connection, and utilizing aluminum wedges, provide for a damper winding on the rotor. In these cases it is important to maintain the tight electrical connection.

On the generators requiring a wedge to ring gap, the gap should be checked whenever the rotor is accessible. If necessary, the wedges will have to be shifted back away from the ring to restore the gap and locked in position. If needed, the OEM should be consulted regarding methods for locking the wedges in position. If the OEM is not available, an experienced service provider may be able to provide proper methods for securing the wedges.

## In Generator Ring Inspection

Even during outages in which the rotor is not to be removed from the generator, some inspection of the retaining rings may be possible. Borescopes and small cameras operated from the ends of the generator can be used to some measure to determine the condition of the retaining rings' surfaces. Service providers offering these inspections of the rings should preferably have references and a proven record of their inspection methods. It is important to note that if the in situ ring inspection finds indication of moisture, arcing, cracks, pitting and other flaws, the rotor will have to be removed for a more thorough inspection and evaluation. Readers are urged to consult the EPRI reports and guide cited in the reference section for further information on inspecting and evaluating the retaining rings.

## Outage Precaution

With 18-5 retaining rings it is important to prevent contact with moisture not only during operation, but also during outages. Given that retaining rings are heat shrunk on the rotor, they are still under great stress even when the generator is shutdown. Stress corrosion cracking can still occur regardless of whether the rotor is in or out of the machine, if moisture is present. During periods of generator shutdown, the rotor should be maintained moisture free by the use of dry hydrogen, carbon dioxide, or an inert gas like argon, with which some have begun testing. Tenting the rotor when it is removed from the generator, and employing heaters or dehumidifiers will greatly aid in minimizing moisture induced stress corrosion cracking. Even if the retaining rings are made from less susceptible stainless steel, such as 18Mn 18Cr, it is still a good practice to maintain dryness of the rotor environment. While 18Mn18Cr stainless steel rings are less susceptible to stress corrosion than 18-5, they can still be susceptible to moisture related problems and should be protected.

## ***Rotor Forging***

As discussed in Chapter Two of this report, the generator is subjected to various forces and stresses which can contribute to rotor damage. A common type of damage is dovetail cracking, which has been widely believed to be caused by fretting. Dovetail fretting is caused by movement of wedges in the slot. This is most pronounced with short steel wedges, occurring at the location of the wedge joints. However, some experts believe that all wedges, including aluminum wedges, cause fretting to some degree.

During operation, the wedges are held firmly in place by centrifugal force. It is during start up, shut down and turning gear operation that wedge movement can occur. It had been thought that this fretting and low cycle fatigue, or LCF, was responsible for dovetail cracking. Rotors which are subjected to higher amounts of LCF are more susceptible to dovetail cracking. These rotors include those with a high number of stop and start cycles, such as with two shifting. A high length to diameter ratio, generator motoring events, and negative sequence current occurrences are also significant factors in the initiation of dovetail cracking.

Recently a number of generator experts, including a major OEM, have performed analyses and studies, and have come to believe that dovetail fretting by the slot wedges is not responsible for initiation of cracking. Their findings indicate that surface currents flowing around the circumference of the rotor are more responsible for crack initiation.

The rotor surface currents, caused by negative sequence currents in the stator or by motoring the generator, can produce heating and arcing on the rotor. The heating and arcing will be more prevalent in areas which concentrate the current, and where the current must cross a joint such as the between the dovetails and the wedges. Pitting and material property changes due to the arcing and heating allow for more metal fatigue from cyclic stresses in the affected areas.

Regardless of the mechanism initiating dovetail cracking, the cracking can often be repaired by machining, if discovered in time. A thorough inspection and nondestructive testing of the dovetail areas should be performed whenever the retaining rings and wedges are removed. The OEM recommendations on inspection tests and schedules should be followed to forewarn of possibly significant damage that could require substantial repairs and extended outages.

Significantly advanced cracking might be noticed during operation by high vibration. Typically complete rotor mechanical failure will not occur as the high vibration forewarns of the cracking problem. However, having vibration monitoring is not a reason to forego rotor inspections. Rotor inspections can prevent excessive repair costs and lengthy outage requirements by providing earlier identification of cracking than is possible by vibration analysis.

Following a generator motoring event or significant negative sequence occurrence, the rotor should be removed and inspected for damage. While an inspection may not be necessary prior to returning the generator to service immediately after the event, the significance of the event or occurrence should be determined; and the OEM, or at least an experienced service provider, should be consulted for recommendations.

At the time of this report a few generator experts believe that inspections for dovetail cracking may be unnecessary, unless a motor or negative sequence event has occurred or if the generator has been subjected to prolonged periods of negative sequence currents. However, unless there is verifiable proof that a generator has not been subjected to negative sequence currents, a baseline inspection should be performed to verify the rotor is in good condition. Furthermore, unless the plant employs a negative sequence current monitor to verify the generator will not be subject to negative sequence currents, additional periodic inspections will still be necessary.

The OEM recommendations regarding rotor inspections and dovetail cracking should be followed. Recommended time periods may be shortened due to operational events, experiences and findings on similar generators, and advice from in house and vendor experts. However, the time periods should not be lengthened beyond the OEM's recommendations, unless concurrence is given by the OEM.

### **Rotor Cleanliness**

Dirt, oil and other debris may hide cracks and other flaws on the rotor and in the wedges and other components. The rotor should be visually inspected prior to cleaning to detect abnormalities such as copper dusting, oil deposit, excessive dirt, signs of overheating, etc. It is important to identify any presence of rust and other evidence of moisture.

Following the initial visual inspection, to better be able to detect cracks and other flaws, and to perform NDE inspections, the rotor should be cleaned as much as physically possible. It is important to ensure a clean rotor to provide cooling and electrical insulation of the field, and to provide for thorough inspections. If moisture indications such as rust are found, a thorough

inspection of the retaining ring should be performed, in particular for 18-5 rings the rings may need to be removed for interior inspection.

Copper dusting, if excessive enough, can lead to field winding grounds and interturn shorts. Electrical winding tests should be conducted if dusting is found during inspections, to detect the presence of shorts or grounds. Though significant grounds may be detected by the field ground detection relay, an insulation resistance test should be performed to detect weak grounds.

## Inspection Methods

As mentioned in the previous section on cleanliness, the rotor surface should be visually inspected prior to cleaning, and also prior to removal of retaining rings and wedges, if these are to be removed. The inspection should seek to identify any signs of contamination, debris, moisture, overheating, copper dusting and other problems, as well as for cracks, pitting and other mechanical defects. If problem indications are found, their location and description should be documented for further evaluation. Additionally, photographs will be beneficial for evaluation purposes and as a historical record. If wedges are to be removed, another inspection should be performed as well, as the wedges may have blocked signs of fretting, dusting and other problems. Additionally, the wedges themselves should be inspected for defects such as cracking.

After cleaning and wedge removal, if applicable, a thorough inspection of the rotor should be performed to identify cracks, fretting and other mechanical flaws which may have been hidden before the cleaning of the rotor. Special attention should be paid to stress concentrators on the rotors and other components, such as holes for cooling gas flow. The holes and other concentrators may be more prone to developing cracking and other defects. Portable lighting and small hand mirrors will aid in inspecting difficult areas.

Defects identified in the inspections should be documented and photographed for evaluation and for added attention during NDE inspections. The characteristics of the defects need to be noted in the documentation, whether they appear to be due to fretting, cracking, overheating, arcing, etc. The size of the defects is important to note, to include the length, width and if possible the depth. The OEM, service provider, or in-house generator expert needs to be made aware of identified defects as soon as possible in case further inspection is required or if corrective action will have to be taken. Certain flaws, if minor, may have been identified and documented in previous outages. This documentation is important to verify whether these flaws have worsened or remained the same. Documentation from inspections in previous outages can be beneficial to the inspectors by identifying known flaws and where added attention may be needed.

### *Dye Penetrant Inspection*

The dye penetrant inspection, or penetrant test (PT) can detect cracks or small defects down to approximately 0.060 inches or 1.5 mm. The fluorescent dye penetrant provides better visibility, allowing for possible defect detection down to 0.030 inches or 0.8 mm. The better visibility by using fluorescent dye is achieved by using a UV light in a darkened environment. Under normal

lighting conditions the use of a fluorescent dye is not advantageous over the use of a non-fluorescent dye. The penetrant test is used mainly when the wedges are removed, as the dovetail region of the slots is the main concern for fretting and crack initiation.

Besides the dovetails, the wedges and other areas of the rotor can and should be inspected with dye penetrant as needed. A detailed rotor inspection is not necessarily a routine task to perform whenever the rotor is removed, as this can be very time consuming. However, due to OEM guidance, a generator motoring event, or a negative sequence current occurrence, a somewhat detailed inspection of certain areas on the rotor surface may be prudent. Particular areas which might receive special attention would be around cooling passage holes and other stress risers, and also similar areas which may concentrate current flow during a motoring or negative sequence current event.

### *Magnetic Particle Inspection*

The magnetic particle inspection offers similar capability as dye penetrant for detecting surface cracks and flaws, and typically can be performed in a shorter period of time. This inspection is also referred to as mag particle, magnetic particle test, MT or MPT. Magnetic particle inspections can only be performed on magnetic materials. Nonmagnetic items, such as aluminum wedges require another inspection technique.

The same rotor areas and components which can be inspected with dye penetrant can be inspected with magnetic particle, except for the nonmagnetic components. Magnetic particle inspection may be difficult to perform in rotor slots due to space and configuration limitations. To perform dovetail inspections, a special probe may be required to reach inside the rotor slots.

Cleaning is required after performing the magnetic particle inspection. Care must be exercised during application, performance and clean up to prevent particle material from getting into winding, cooling passages and other areas.

The rotor should be checked for residual magnetism before returning to service.

### *Eddy Current Inspection*

Eddy current inspections are more sensitive and faster than dye penetrant and magnetic particle inspections. This inspection is also referred to as eddy current test, ET or ECT. This technique can be employed on any conductive material, and thus can be used to inspect aluminum wedges.

The equipment to perform eddy current inspections is more expensive than dye penetrant material, and magnetic particle inspection material and equipment. Additionally, a higher skill level is required to both perform the eddy current inspection and analyze the results. Fretting, arc strikes and other surface abnormalities may prevent the detection of small cracks beneath them.

Still the eddy current method offers a number of advantages for inspecting the rotor, including higher sensitivity. Also, once initially purchased the eddy current inspection does not require additional purchases of expendable inspection materials. Since is no inspection material required, no clean up is needed after the inspection.

### *Ultrasound Inspection*

Ultrasound inspections like eddy current inspections require skilled and experienced inspectors, and are typically quicker than either the dye penetrant or the magnetic particle methods. The ultrasound method provides the ability to see inside the material being inspected, even may allow inspection of an opposite surface through the material. Thus, there is some capability to allow dovetail inspection without wedge removal.

A complex geometry of a volume under test can make ultrasound ineffective; scattered sound waves and reflections can cause some flaws to go undetected and may produce false indications. Skill and experience are often required to correctly position the probe and scan the material under test, but even then the shape of the material may prevent accurate readings.

Some have reported success with phase array ultrasound in inspecting rotor dovetail areas from the rotor surface with wedges installed. In phase array, several ultrasound waves of the same frequency are emitted from the test probe with each wave's phase shifted based upon where from on the probe the wave is emitted. The shifted phasing, which is adjustable, steers the ultrasound beam at a desired angle from the probe. Thus, the probe can be held flat against the rotor surface, while the beam is directed at an angle to a side surface, such as the dovetail area. Additionally, by varying the phase shifting, the beam can be swept through various angles to sweep and inspect a wider area, without moving the probe.

To be able to verify that an ultrasound inspection will be able to provide accurate results of the dovetail surface, or any other far surface through a material volume, a calibration block should be utilized. The calibration block is a sample of the similar material and with same geometry of the volume to be inspected. For dovetail inspection the calibration should a replica of a short length of a rotor tooth, with the same cross sectional shape and dimensions. The calibration block needs to have defects created in it at known locations, with the defects made to the actual defect sizes that should be detected by the inspection. To verify the ultrasound inspection procedure, the inspector needs to inspect the calibration exactly as will be done on the rotor. The results should identify all known defects and not produce any false positives.

### **Rotor Inspection Practices**

Based upon information provided by utilities and service providers, the following is an overview of typical dovetail inspections. Not all plants necessarily follow the overview exactly; but many that have provided information to this project, have indicated processes similar to the following:

- Perform visual inspection of rotor and wedges.

- Clean the rotor.
- Perform second visual inspection after cleaning.
- Perform magnetic particle inspection if wedges and winding are removed.
- Perform eddy current inspection if wedges are removed, regardless of whether the magnetic particle inspection was performed.
- Use dye penetrant to inspect areas which may not have been adequately inspected by the other techniques or where inconclusive results were obtained.
- Perform ultrasound testing if wedges are not removed.
- The retaining rings should be inspected with the rotor.
- If the rings are removed, the end teeth will need to be inspected also, with attention given to top tooth cracking on units known to be susceptible to this problem.
- Rotor fans, couplings, rotor shaft and other rotor components also should be inspected with the rotor forging inspection.

Items in the above list should not be used if they contradict OEM recommendations. The OEM recommendations and guidance should be followed. The rotor does not typically need to be inspected every outage; but whenever OEM recommendations specify, or sooner based upon past inspection findings, operational history, online monitoring and advice of in house or vendor generator experts.

If the generator was exposed to significant negative sequence currents or if it was motored by being connected to the power grid without its field energized, the rotor will need to be inspected for possible damage. Whether the generator should be allowed to return to operation prior to an inspection will depend upon the severity of the event, and upon recommendations by the OEM or other experienced generator experts.

Regardless of whether the generator is permitted to return to operation, the rotor will still need to be inspected as soon as practical. Minor damage to the rotor may not have an immediate impact on continued operation for a limited time period; but the damage may worsen over time, and thus needs to be detected and repaired when possible.

Hardness testing may be required in areas where overheating from high current and arcing had occurred. High heat may have soft or hardened the rotor steel in these areas. Affected areas may require shot peening to correct the hardness, or may require machining to remove the affected material. Rotor machining will require carefully analysis and evaluation to ensure rotor strength is not adversely affected. The OEM or a well experienced service provider will usually need to be brought in to support, if not direct, the project.

Based upon the findings from the inspections, additional inspections may be required. If wedges were not removed and ultrasound inspection identified possible cracks in the dovetail area, the wedges will need to be removed for further inspection of the affected area. Depending on the

number and extent of defects identified, all the wedges may need to be removed for a complete rotor inspection, or possibly only just enough wedges to inspect the slots in the affected area.

Identified defects should be well documented, preferably accompanied with photographs. Include in the documentation the defects' size, location, depth and other pertinent data. The documentation will serve to provide data for evaluating the condition of the rotor, provide baseline data for future inspections, and if repair is required, will give information needed to properly plan and implement the required work. Required work may include machining the cracks and other defects out of the rotor; and also possibly machining portions of the rotor to remove stress risers to prevent future problems. The OEM or a well experienced service provider will need to be brought in to direct, or at least support, the project to ensure that the structural integrity of the rotor is not compromised.

### ***Top Tooth***

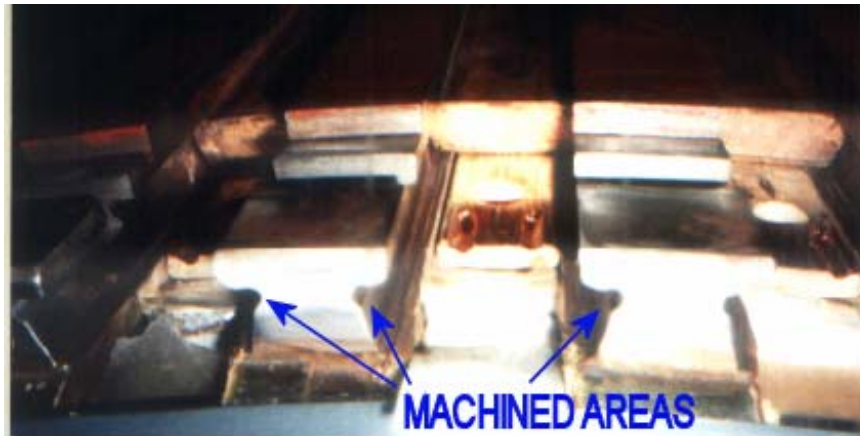
Certain rotor designs with rotor or body mounted retaining rings have the potential for top tooth cracking, particularly in older generators. Susceptibility of this problem varies with rotor design. Pressure from the heat shrunk ring significantly stresses the teeth under the ring, and during operation centrifugal force reduces these stresses. Cyclic operation of the generator varies the stresses on the teeth creating metal fatigue. The locking key groove concentrates the stresses and increases the fatigue. On susceptible rotors, when cracking occurs it typically forms between the groove and tooth end.

The tooth tops under the retaining rings should be inspected and have non-destructive examinations performed whenever the retaining rings are removed. To thoroughly inspect the tooth tops the end wedges will have to be removed. Inspection of the end teeth is similar to inspection of the rotor teeth for dovetail cracking; involving visual inspection, dye penetrant, eddy current and ultrasound as needed.

Due to the expense of removing the rings and wedges, plants may desire to plan tooth top inspections based upon its own and industry experience with the particular rotor design; though, they should still follow OEM recommendations to the extent practical. Deviations from the OEM recommendation should have OEM concurrence, or at least involve consultation with the OEM to ensure the plant has accurate knowledge of the potential risks involved.

As mentioned previously, areas such as the locking key groove can be stress concentrators and be prone to crack initiation. Inspectors need to pay extra attention to these areas on rotors with body mounted rings. If cracking is found in the tooth top areas, a repair is frequently possible. Repairs often involve machining out the cracks and other defects. Furthermore, to prevent recurrence of this issue, the repair will usually include modifying the shape of the end teeth, and the locking groove and other stress concentrators. The OEM should be consulted on recommended repairs and modifications, as they likely have had experience with repairs on other similar generators. The following image shows smooth bends machined into the dovetails of the end teeth, to remove the sharp angled stress risers.





**Figure 4-3**  
**Modified End Teeth**

Courtesy of Márcio Rezende Siniscalchi, ELETRONUCLEAR

### ***Other Rotor Components***

#### **Fans**

Fan blades or vanes should be inspected when possible. The attachment area of the blades or vanes to the fan hub can be subjected to fatiguing stresses. Fans should be thoroughly examined, with particular attention to where the vanes or blades are attached. Examination should include both visual and NDE inspections, such as dye penetrant testing; however past inspections and experience may limit the need for NDE inspections.

Typically the fans have a hub which shrunk onto the rotor shaft. The fan hub and the shaft are under constant stress from the shrunk fit. Cyclic operation and any torsional vibration can lead to metal fatigue and cracking. The hub should be inspected visually and with NDE means. Whenever the fans are removed from the shaft, the inside of the fan hub and the shaft's hub area should be thoroughly inspected, with particular attention to keyways and other stress risers.

Whenever the rotor is removed from the generator the fans should be at least visually inspected, to include the vanes or blades, and the hub. OEM guidance, experience with one's own generator and from plants with similar generators, and past inspection results may necessitate fan inspection, even when no other rotor work is planned to be performed.

Some generator may have gas guides or baffles fitted onto the shaft to direct cooling gas flow. These are subjected to the same forces as the fans. The guides, if present, should be inspected at the same time as the fans, using the same techniques.

## Couplings

The generator couplings have a large amount of stress on them. First there is the torque from the prime mover, or the torque to drive a rotating exciter. A shrink fit of the coupling on the shaft will produce a hoop stress acting continuously on the coupling. Generator start ups and shut downs place varying stress on the coupling, and also on the shaft where the coupling is fitted. Torsional vibration creates cyclic stresses which may lead to fatigue. Additionally, any misalignment will create further cyclic stresses, potentially leading to more fatigue and the fretting of the coupling and shaft.

During maintenance outages the couplings should be at least visually inspected. Prior experience and operating history may call for more thorough examinations to include NDE. Whenever the couplings are removed, the interior of the coupling and the rotor shaft should be examined for wear and fatigue. Special attention during examination should be paid to keyways and other stress risers.

## Centering Rings

The retaining ring centering or balance rings should be inspected along with the retaining rings. Spindle mounted retaining rings have a spindle on which they are fitted, instead of a centering or balancing ring. The spindle is typically part of the rotor forging, but for purposes of inspection in this report it is treated the same as the centering ring.

The retaining ring is shrunk onto the centering ring, putting a large amount of stress on the centering ring. Centrifugal force during operation relieves some of this stress. Cyclic generator operation can produce varying stresses, leading to low cycle fatigue of the centering ring.

Whenever the retaining rings are removed, the centering rings should be thoroughly inspected, to include NDE inspections. As with other components, the lock key groove and other possible stress risers should receive added attention during inspections.



**Figure 4-4**  
**Rotor with Retaining Ring and Centering Ring**

**Courtesy of Márcio Rezende Siniscalchi, ELETRONUCLEAR**

### Balance Weights

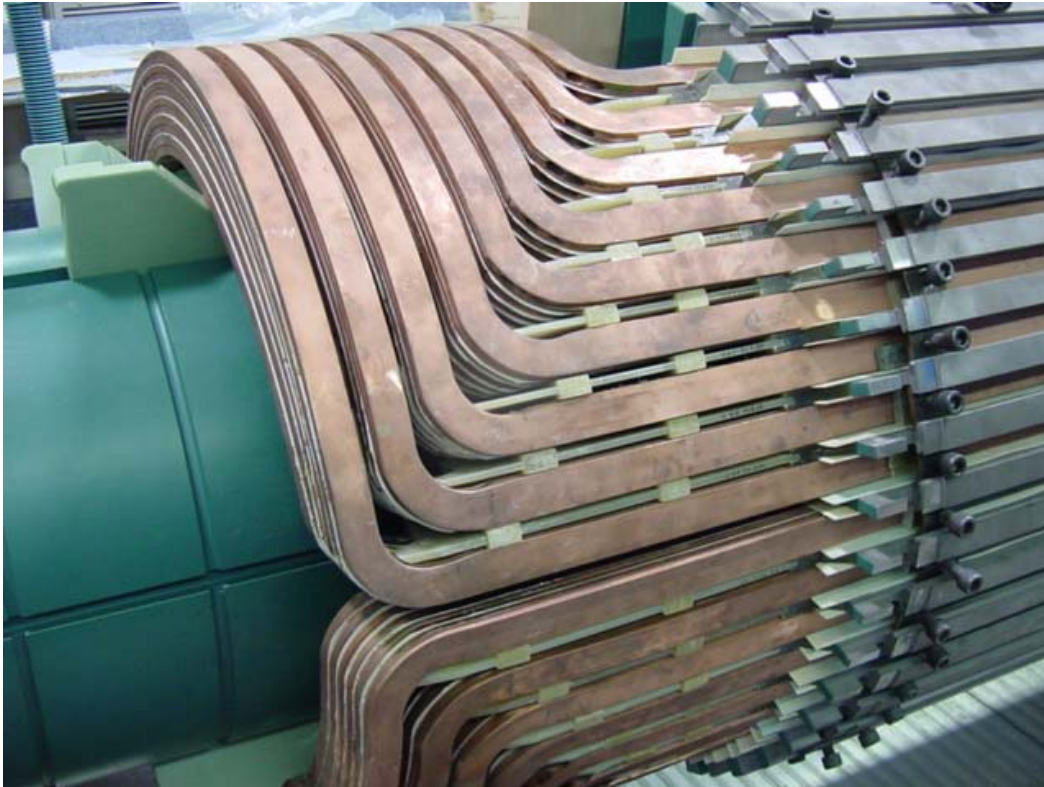
Balance weights are used on all generators, and these do not require detailed examination. The concern with balance weights is that they not come loose during operation; at operational speeds on turbine generators, significant damage can result. Inspection of balance weights during rotor removal, particular when rotor work has been performed, is to verify that the weights are securely locked to prevent loosening.

### End Turn Area

The field winding ends or end turns are secured radially by the retaining rings. Insulated blocking secures the end turns to maintain each end turn's position in respect to other end turns. Loose blocking can allow end turn movement, and lead to deformation and possible winding failure.

Additionally, at the collector or exciter end of the rotor the main field leads make connection with the field winding. The leads are secured in position, but have to allow for thermal expansion of the winding conductors. Typically the main leads at the winding connections are

made of copper sheets to allow for winding conductor expansion. Loose blocking and/or vibration can lead to fatigue failure of the lead conductor sheets.



**Figure 4-5**  
**End Turns**

**Courtesy of Portland General Electric**

The turns and leads in the end winding area under the retaining rings is not easily accessible and cannot be readily inspected. Some success in inspecting the end turns and main leads, without removal of the retaining ring, has been accomplished using borescopes, mirrors and portable lighting. Even if the entire area cannot be inspected, an assessment of the condition of the end turns, leads and blocking may be gained from a partial inspection. A more detailed inspection, if necessitated by OEM recommendation or indications from other tests, will typically require retaining ring removal, and possible removal of the outer end turns.

### Bore Copper

The field current is carried to the field winding through the turbine generator shaft by two copper conductors, or the bore copper. Radial studs conduct the current into the bore at the collector or diode end, and out of the bore to the field winding. Not all generators will have radial studs on the outboard end of the rotor shaft. Brushless exciter generators may employ a butterfly connection at the exciter end of the shaft.





**Figure 4-6**  
**Radial Stud with Field Lead**

**Courtesy of Portland General Electric**

The radial studs are often difficult to inspect without some rotor disassembly. Bore copper inspection is almost impossible without removal, even with rotor disassembly. The insulation resistance test is the best method to evaluate the condition of the bore copper insulation and radial stud insulation; these are tested simultaneously with the field winding when performing an insulation resistance test.

With some disassembly of the field circuit, the radial studs can usually be removed, typically to inspect the hydrogen seals. When removed, the condition of the studs can be inspected. Also, a borescope might be able to be used in the stud holes to partially inspect the bore copper ends on some generators.

The radial studs at one or both ends of the bore copper typically have a hydrogen seal to prevent leakage of hydrogen back through the shaft bore. Obviously on air cooled generators, there will not be hydrogen seals. On hydrogen cooled generators, the seals cannot usually be inspected without removal of the radial studs. Often when seal integrity needs to be verified, a pressure test is performed. A test device is fitted over the seal, and pressurized to a test value above operating pressure. If the seal holds the pressure it is deemed to be good, otherwise it will need to be replaced.



# A

## BEST PRACTICES

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The following list consists of “good practices” from utilities that have had successful experience with maintaining their generator rotors. Many of these utilities have also rewound or refurbished their generator rotors. These practices are ordered into fairly broad groups of similar topics, and the order does not represent a particular precedence or importance of any particular practice. Not all practices will be applicable to every generator; readers are recommended to review the entire list and determine which are applicable and significant to their own units.

1. Consider possible design modifications, to correct low cycle fatigue on pole to pole connectors and other links. A possible modification is to install flexible pole to pole connections to deal with cyclic fatigue failure issues.
2. Rotor overheating issues and upgrade concerns can be often addressed with a new rotor of advanced design for better cooling.
3. When uprating a generator, determine if increased hydrogen pressure is needed to enhance cooling capability and if a design modification is required for increased pressure.
4. Consider installing an enhanced slot cell insulation system comprised of fire resistant aramid fiber material layered with epoxy glass tape, or a similar system, during rotor refurbishment to add higher mechanical strength.
5. Reliable and cost effective field insulation with a proven performance record on similar units should be required for rotor rewinds.
6. Class F or better insulation (class H) should be required for new field windings.
7. Use a DC shunt for field current monitoring, which is fairly common. Some generators may employ a transducer for obtaining a representative signal of the field current for an ammeter or current monitoring device. However, in some instances the calibration of the transducer has been found to be incorrect.
8. Install a negative sequence current relay and meter or monitor. Modern digital negative sequence relays are more accurate and sensitive than electromagnetic relays.
9. Consider a spare rotor to address aging and operational hazard concerns, and to maximize generator availability.
10. When maintaining a spare rotor, the installed rotor should be changed with the spare periodically. Have the spare rotor checked and maintained in the OEM or a service provider's facility.
11. Maintain a spare rotor, with a consortium of similar plants. Replace generator rotors with spare every ten years, and inspect and maintain the removed rotor as the new spare.

12. Preplanning for possible rotor trouble and failure emergency response planning can save unscheduled outage downtime.
13. Consult OEMs and service providers for recommended spare parts, material and tools that should be available at the plant for rotor repair and maintenance.
14. Rotor failure contingency plan should include special tools and materials for at least a partial rewind of rotor.
15. Contingency planning should include plans of action and procedures to implement rotor repair for various potential failure scenarios.
16. Preplanning contingency plans must be agreed upon and approved by management of maintenance, operations and other organizations that may be involved in the repair.
17. A permanently installed air gap flux probe is the most important instrumentation to indicate shorted field winding turns. This is especially important if the refurbished rotor was not flux probe tested for shorted turns in a spin pit before installation.
18. Perform periodic checks on the rotor shorts at increased frequency when field winding problems is suspected. Continuous, on-line flux probe monitoring helped one plant to detect shorts that occurred as a result of grid transients.
19. Cyclic operating cycles and aging often result in a trending up of equipment problems and failures. This can continue in spite of increased maintenance and testing. Rotor refurbishment or replacement may be required to correct this trend
20. Priority should be given to replacing retaining rings on generators with a history of poor hydrogen dew point, and on units with water cooled rotors having a high potential for moisture in the hydrogen.
21. Verification of a vendor's references, and shop inspections, should be performed prior to awarding a contract.
22. Timely and reliable delivery of materials can be a problem on complex projects. Prior to implementation of project, located vendors who are very responsive to plant needs for special materials and can provide reliable service.
23. Consider utilizing OEM for technical overview and consulting on non-OEM rotor refurbishment and replacement projects.
24. After the rotor rewinding and insulation curing cycle, winding electrical tests should be performed before and during an overspeed test.
25. To ensure quality of work, a utility person should be at the rewind facility for the duration of the rewind and testing of the rotor.
26. Ensure accurate alignment of the rotor.
27. The slot liners in older fields may contain asbestos. A qualified asbestos abatement contractor will be required to remove these slot liners.
28. Cleaning of components and any other mechanical items should be done outside the rotor clean area.



29. When rewinding, consider replacement of 18Mn-5Cr retaining rings, and inspection for tooth top and dovetail cracking, as well as making necessary repairs.
30. It may be possible to delay change out of, or even not change, out stress corrosion susceptible retaining rings, if hydrogen dryness has been maintained and periodic inspections do not reveal a problem. When the rotors are out of the machine, place them in de-humidified enclosures to prolong life of susceptible rings.
31. Retaining rings should be replaced when flaws are discovered.
32. Stress relief machining of tooth top areas on the shoulder can be effective; provided that nondestructive testing shows that there cracking does not extend deeply or beyond the modification area. When cracking is too deep machining, the rotor teeth geometry is modified to remove high stress concentrations.
33. When rewinding a field due to shorted turns, a determination of root cause for the short is necessary. The organization performing the rewind of a winding with shorted turns should be required to identify and locate the shorts for further inspection and examination. A root cause analysis should be performed to determine the cause of the shorts.
34. Document all steps and findings during rotor refurbishment and repairs with digital photographs.
35. The organization performing a rewind due to winding faults, should take sample of winding for examination. Samples taken should include the areas of failed insulation, along with the conductors at these areas.
36. It is not necessary to rely solely upon the OEM for the entire refurbishment or replacement project.
37. A high speed balance after rewind of the rotor is not always necessary if the original copper is re-installed.
38. Predictive maintenance and condition monitoring can forewarn and provide information of deterioration in the rotor.
39. To detect stress corrosion cracking and other flaws in the 18Mn-5Cr retaining rings, the following tests are recommended: liquid penetrant inspection; eddy current testing; and material samples taken for analysis if indications of flaws are found.
40. Whenever possible perform a boroscope investigation of the underside of the retaining rings. Inspect the end-windings for signs of distortion and wear. If significant damage is found it may indicate a problem that to be addressed before the rotor is put in service.
41. The interior of the retaining rings tends to capture and hold moisture; it should be thoroughly inspected on stress corrosion susceptible retaining rings at every opportunity.
42. When removing rotor fans, coupling and other shrink fitted shaft mounted items, inspect shaft for cracks. Perform stress relief machining on susceptible units.
43. Use eddy current testing after dye penetrant inspection to determine depth of tooth top cracking if needed.

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*Best Practices*

44. Generator practices, methods and techniques should be exchanged between nuclear and fossil units.
45. To provide for continued electrical production while a rotor is being refurbished, obtain a replacement rotor. Rent a rotor if necessary, and if available.
46. Know what the rotor current is. The current is used to calculate rotor average temperature by winding resistance method. If the current reading is inaccurate, the temperature will also be inaccurate.
47. The use of hydraulic coupling bolts speeds disassembly and reassembly. Also, ensures correct bolt tension, and prevents galling and other damage.

# **B**

## **LESSONS LEARNED**

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The following list consists of “lessons learned” from utilities that have rewound or refurbished their generator rotors. Like 'best practices' in Appendix A, these lessons have been ordered into fairly broad groups of similar lessons, and the order does not represent a particular precedence or importance of any particular lessons. Not all lessons will be applicable to every generator; readers are recommended to review the entire list and determine which lessons are significant to their own units. Some of the “lessons learned” may duplicate “best practices” provided by other utilities in Appendix A.

1. During repair of many types of turbo rotors, it has been found many rotors were not specifically designed for the application and environment in which the generators were employed.
2. Consideration to the hydrogen seal design type & clearances, and seal oil flow rates are important if they are being changed with the new rotor. Changing the hydrogen seal design, particularly when the new rotor and stator are not OEM, may result in different seal oil flow requirements and different seal clearances.
3. Replacement of stress corrosion susceptible retaining rings with non-susceptible rings, and the stress relief machining of rotor teeth, may extend the useful life of the rotor.
4. Fatigue cracks can often occur in rotor slot tooth tops primarily outside the snap ring groove. Cracks are caused by cyclical stresses acting on the tooth tops. This problem is not restricted to any particular style of generator or a particular manufacturer. It can be present on any rotor where the teeth are sandwiched between the slot wedge and the retaining ring.
5. Rotor design modifications may be necessary to minimize low cycle fatigue cracking of retaining ring seats and pole to pole connectors with generators not specifically designed for high cycle operation.
6. Several recent surveys indicate that a significant portion of the installed generators operate with shorted turns.
7. Without contingency planning to handle potential failures, the duration of an unscheduled outage due to rotor failure can be extended by days, weeks or even months.
8. A flux probe monitoring system should be employed. It requires monitoring at various load points. Initially, trend frequently until a database of operating conditions is established.
9. Cycling a generator is a major cause of the main lead failures, insulation deterioration and overall deterioration of the generator field. Running the generator at a constant load and with less start ups and shut downs will help minimize these problems. Two shifting creates accelerated wear and fatigue on rotor components, such as pole to pole connectors.

10. Generators with higher VAR loading can have shortened rotor life expectancy due to higher field current and higher field temperature.
11. Replacement of the retaining rings with 18Mn 18Cr rings eliminates requirements for frequent inspections; however, it is still important to continue monitoring and maintaining hydrogen dryness to ensure insulation integrity and prevent accumulation of moisture.
12. Incorrect switching of generator output breakers has caused generator motoring from standstill. Arcing damage to the retaining ring and wedges can introduce crack initiation sites.
13. Typical field temperature monitoring systems can be sensitive to voltage and current readings errors and inaccuracies. Need to understand limitations of the system when assessing rotor temperatures.
14. The plant should verify the ground detection system is operating properly. It is important to immediately identify field grounds.
15. Ensure a thorough technical review of the materials and methods to be used by vendor for rotor rewind and refurbishment of rotor. If experiencing rotor trouble or faults after refurbishment immediately re-assess the vendor's materials and methods to determine rotor reliability for continued operation.
16. Oversight of vendor should be required on rewinds and refurbishments. In one case the repair vendor was not using a spreader bar during wedge installation, resulting in slot liner damaged.
17. To utilize turbine house cranes in a tandem lift arrangement, replace the motors and resistance controllers on the long- and cross-travel drives of the cranes with variable voltage variable frequency drives and motors. This makes tandem lifts much easier for the crane operators, and much more controllable as the speeds of the two cranes can be much more closely matched.
18. The rotor refurbishment shop should have a clean room that is temperature and humidity controlled.
19. Inspect rotor and perform field electrical testing at the shop after refurbishment or rewind, and high speed balance.
20. Cleanliness is very important during the rewinding. The generator forging must be clean before any repairs are started.
21. During any grinding, buffing of the copper components the new insulation and other copper components must be masked off to keep debris out of the new windings.
22. Large and difficult lifts can be simplified by equipment disassembly. In one example, a rotating exciter and pilot exciter are mounted on a common bedplate at the end of the generator. According to the OEM maintenance manual, it is possible to pick the exciters up on the bedplate and move them it out of the way. It is found to be much easier to disconnect and remove the exciters, and then remove the bedplate. The plant ends up with more individual parts to lay down, but generator disassembly and re-assembly are much easier.

23. To determine the presence of field winding shorts, the Recurrent Surge Oscillography (RSO) test was not as conclusive as the air gap flux monitor.
24. Reliable and accurate determination of remaining life is generally not possible. Periodic inspection and predictive maintenance test data should be used to assess and determine rotor reliability for next operating cycle.
25. Ultrasound inspection of the retaining rings is not always reliable. The grain structure of 18Mn 5Cr material is very coarse, resulting in a high level of residual signal. Additionally, UT sensitivity and the resolution are harmed by reflections from the interference fit of the ring with the rotor. Interpretation of the results can be complicated by the complex geometry of the ring in the areas where cracking is more probable.
26. Some rings forged in recent decades may contain nonmetallic material inclusions and abnormalities that can be detected in eddy current and ultrasound tests.
27. To assess field reliability for another operation cycle perform routine standard electrical testing on field windings during outages. Perform pole balance and turn to turn testing when possible, if a flux probe monitoring system is not installed.



# C

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# **E**

## **GLOSSARY**

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**18Mn 5Cr** - steel alloy with 18% Manganese and 5% Chromium. Is susceptible to stress corrosion cracking.

**18Mn 18Cr** - steel alloy with 18% Manganese and 18% Chromium. Not susceptible to stress corrosion cracking.

**AEI** - Associated Electrical Industries, British generator manufacturer, purchased by GEC and subsequently became part of Alstom.

**Aramid** - a synthetic fire resistant and high strength fiber. Commonly known brand names are Nomex and Kevlar.

**Brush** - typically a carbon based block used to transfer electrical current between the stationary and rotating components of a generator. Also, see collector.

**Brush Pressure** - the pressure on a brush that forces the brush against the rotating collector or commutator to maintain electrical contact. Equal to the spring force applied to the brush divided by the brush's cross-sectional area.

**Brushless Excitation System** - an excitation system that employs an alternator with a stationary field and a rotating armature, so brushes are not required to contact the alternator's output to the generator's rotating field. Shaft mounted diodes rectify alternator's output to DC for the generator field.

**CGE** - Canadian General Electric

**Collector** - a component in many generators and alternators for transferring current between stationary and rotating elements. The collector consists of rotating slip rings and stationary brushes that provide low mechanical friction and low electrical resistance.

**DHIC** - Doosan Heavy Industries & Construction Co., Ltd. Korean Manufacturer.

**Exciter** - the alternator or DC generator that supplies the electrical power for the excitation system to produce the main generator's field current. Generally, any component that supplies the electrical power to produce the main generator's field current.

**Field** - the DC winding of a generator; produces the magnetic field for generator excitation.

**GEC** - General Electric Company plc, British manufacturer

**IEC** - International Electrotechnical Commission

**IEEE** - Institute of Electrical and Electronics Engineers.

**Insulation Resistance Test** - an electrical test that assesses the condition of electrical insulation by applying a fixed DC voltage across the insulation.

**Interturn Short** - an electrical short between adjacent turns of a winding.

**LCF** - Low Cycle Fatigue.

**Leakage Current** - the surface current flowing from the insulation, which is constant over time. Insulation damage, defects, moisture, and other conductive contaminants can greatly increase the leakage.

**NEMA** - National Electrical Manufacturers Association.

**OEM** - Original Equipment Manufacturer.

**Ohm's Law** - the relationship between voltage, current, and resistance: voltage across a component is equal to the current flow through the component multiplied by the resistance of component ( $V=IR$ ).

**Operational Cycle** - the time duration from one scheduled maintenance outage to the next, during which the generator is continuously run or expected to be ready to run. May include within this duration generator downtimes due to economics, decrease load demand, or for equipment failure.

**Power System Stabilizer** - a component or circuit that automatically alters voltage regulator output to oppose power system oscillations.

**Predictive Maintenance** - test and inspection techniques and technologies that are performed to assess component condition and predict possible future failure or malfunction of the component. The intent of predictive maintenance is to forewarn equipment deterioration early enough that corrective actions can be planned and implemented prior to an actual failure or malfunction.

**Preventive or Preventative Maintenance** - time-based maintenance tasks that are performed to prevent malfunction or failure of a system or component, prior to any actual indication of trouble.

**Rotor** - the rotating element of a generator or motor.

**Stator** - the non-rotating magnetic core of a generator or motor.



**Stress Corrosion Cracking** - failure mechanism of metal requiring a tensional stress in the presence of moisture, resulting in the initiation and propagation of cracks in the material.

**Torsional Vibration** - oscillations in the rotational speed of a component.

**Two Shifting** - the practical of running a generator for a portion of the day when load demand is high, and then shut down the generator for the rest of the day.

**Vibration Analysis** - the techniques and technology for collecting and analyzing vibration data. Used not only to determine if accepted vibration limits are exceeded, but also to determine the location and cause of vibration problems.

**Vibration Monitoring** - routine monitoring of vibration levels of a component to determine if acceptable levels are exceeded or if an adverse trend is developing.






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